



Gas inquiry 2017-2025

Interim report

July 2020



Australian Competition and Consumer Commission

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Acronyms

ACQ	annual contract quantity
CCA	Competition and Consumer Act 2010 (Cth)
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DWGM	Declared Wholesale Gas Market
EBIT	earnings before interest and taxes
EBITDA	Earnings before interest, tax, depreciation and amortisation
FID	financial investment decision
GJ	Gigajoule
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
HHI	Herfindahl—Hirschman Index
JKM	Japan Korea Marker
LNG	liquefied natural gas
MDQ	maximum daily quantity
MMBtu	Million British Thermal Units—see below, Units of Energy
MOU	Memorandum of Understanding
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
PJ	Petajoule
REPI	ACCC's Retail Electricity Pricing Inquiry
RIS	Regulation Impact Statement
STTM	Short-term trading market
TJ	Terajoule

Organisation	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIE	Australian Industrial Energy
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
COAG	Council of Australian Governments
GBJV	Gippsland Basin Joint Venture
GMRG	Gas Market Reform Group
IPART	Independent Pricing and Regulatory Tribunal
ICE	Intercontinental Exchange
PWC	Power and Water Corporation
RBA	Reserve Bank of Australia
SGH	Seven Group Holdings
Pipelines	
AGP	Amadeus Gas Pipeline
CGP	Carpentaria Gas Pipeline
DDP	Darling Downs 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
PCI	Port Campbell to Iona Pipeline
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
WGP	Wallumbilla Gladstone Pipeline

Overview

This is the July 2020 interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry).

The focus of our mid-year report has typically been on the forecast supply outlook for the East Coast Gas Market for the following calendar year. This year we have also considered the effects on the East Coast Gas Market that have arisen as a result of both the COVID-19 pandemic and the significant falls in oil and LNG prices.

The impacts of these twin shocks have been felt at all levels of the supply chain and brought into clearer focus the pressure points and areas of dysfunction present in the market. The effects we are seeing in the East Coast Gas Market increasingly indicate a limited degree of competition in key parts of the supply chain. The cumulative effect of dysfunction at the production, commodity gas sales and pricing, and gas transportation levels of the market is significantly affecting gas users at the end of the supply chain.

Many commercial and industrial (C&I) users were already struggling as a result of the increases in domestic gas prices that have occurred over the last five to ten years. For some, COVID-19 has brought new opportunities. Some manufacturers, for example, have been able to change their operations to produce essential products, such as hospital grade hand sanitiser, while others producing essential goods, such as toilet paper and food products, significantly increased output during the height of the pandemic.

However, many C&I users are starting to feel the effect of the contraction in economic activity brought about by the COVID-19 pandemic. Some C&I users have noted that shutting their business temporarily in response to COVID-19 may lead to permanent closure.

While some larger C&I users have reported a softening in the prices offered under gas contracts since our last report, they are sceptical that this will continue given the tight demand-supply balance and what they see as a limited degree of competition among suppliers. They also continue to be frustrated by the fact that domestic prices have not followed LNG netback prices down, what they see as onerous non-price terms and conditions, including high take or pay obligations, and a more general imbalance in bargaining power when negotiating with producers and retailers.

Our examination of prices offered and agreed in contracts over the final quarter of 2019 and early 2020 suggests that reductions in LNG prices may have been at least partially flowing through to the domestic East Coast Gas Market ahead of the impact of COVID-19. The prices offered over late 2019 to early 2020 were in the \$8–11/GJ range, down from the \$9–12/GJ range we reported in our January 2020 report. However, this slight softening in domestic prices compares unfavourably with the level of reductions seen in LNG markets. Domestic prices in Queensland have now diverged from export parity LNG netback prices by more than \$2/GJ.

This pricing behaviour raises questions about the degree of competition that currently exists in the supply of gas in East Coast Gas Market, at both the producer and retailer levels.

The fact that LNG producers collectively sold 18 LNG spot cargoes into international markets at prices substantially below domestic gas price offers during this time increases our concerns about the level of competition in the market. Viewed alongside the divergence between LNG netback prices and domestic prices, these sales highlight the need to better understand what is driving the price divergence and the importance of the ACCC's further work in this area. It may also be appropriate for the Commonwealth to consider extending and/or strengthening its Heads of Agreement (HoA) with the LNG producers, which is currently due to end in 2020.

While the fall in oil prices has brought some short-term price relief to some domestic users, it has also increased the risks and uncertainty surrounding the adequacy of future gas supplies in the east coast to meet demand.

A significant risk facing supply is the impact of low oil prices on upstream investments. As we observed in our 2015 East Coast Gas Inquiry, low oil prices can stifle investment in new sources of supply by reducing both the ability and incentive of producers to explore for and develop gas.

This risk may be exacerbated in the current environment, where the longer term effects of COVID-19 on future demand (and therefore oil and gas revenues) and capital markets is highly uncertain. At present, it appears that COVID-19 has had little effect on the overall level of production in the east coast over the first five months of 2020 compared to the same period last year, although we have observed some regional differences. Production in the Southern states, for example, has fallen, while production in the Cooper Basin and Queensland has increased. Whether this trend will persist is unclear, but we will continue to monitor the effects of COVID-19 on supply.

The risks associated with low oil prices and their impact on future supply brings into stark relief the risks the East Coast Gas Market faces in respect of the supply and demand outlook in the medium term, which we identified earlier this year and which the Australian Energy Market Operator (AEMO) also raised in its 2020 Gas Statement of Opportunities (GSOO). The forecast supply outlook for 2021 only serves to emphasise this.

While supply is currently expected to be sufficient to meet demand in 2021 and the outlook is less tight than it was for 2020, uncertainty is higher because a greater proportion of production is forecast to come from undeveloped 2P reserves. This is particularly an issue in the southern states, with 21 per cent of forecast production in 2021 to come from 2P undeveloped reserves (compared to eight per cent for 2020, at this time last year). If for any reason these reserves are not developed, or development is delayed, more gas from Queensland and, in particular, from LNG producers, may need to flow south.

Our examination of gas producers' actual production levels compared to their previous forecasts shows there is some sign that the market will respond to meet demand. Specifically, it appears that LNG producers will act to produce enough gas to meet demand, although they have not been consistent in this regard. The LNG producers' production levels were, for example, significantly lower than forecast in 2017 and 2018, but in 2019 they produced and supplied more gas into the domestic market than forecast (and when production from southern producers was lower than forecast).

Even if gas users in the southern states are able to rely on gas production from Queensland producers, the level of risk for these users is further heightened by the need to obtain capacity on key transmission pipelines to transport gas from Queensland to the south. Our examination of these pipelines has shown that the South West Queensland Pipeline (SWQP) and Moomba to Adelaide Pipeline System (MAPS) are contractually congested, and while utilisation data indicates that there is scope for the SWQP to be utilised to move more gas south, there is little unused physical capacity on the MAPS during peak periods.

In the case of the SWQP, those seeking to transport gas south may be able to utilise as available/interruptible services, capacity trading, the day-ahead auction or gas swaps. This does not, however, remove the inherent uncertainty associated with relying on non-firm services to transport gas. Further investment in both the SWQP and MAPS is therefore likely to be required to bring more gas south and to facilitate more competition between suppliers in the north and the south.

In this regard, our most recent examination of gas transportation agreements (GTAs) indicates that most have a term of 1–3 years. This is an improvement on what we observed

in 2019, where most contracts had a term of 12 months or less, but contract terms of this length are not sufficient to underwrite an expansion of capacity or the construction of new transport infrastructure. It is also not clear that the parties with the ability to underwrite construction of a new or expanded pipeline are either willing to do so or in need of further firm capacity SWQP and MAPs.

There is forecast to be sufficient supply to meet demand in 2021 but there is increasing uncertainty around supply forecasts

The production forecasts originally provided to us by producers for this report, and the demand forecasts that AEMO prepared as part of the 2020 GSOO, were developed prior to the COVID-19 pandemic related shutdown that commenced in March 2020 and the recent significant fall in oil prices. We have since received updated production forecasts from producers, as at May 2020.

It appears that the pandemic has not had a material effect on the overall level of production or consumption in the East Coast Gas Market in the first five months of 2020, although it differs somewhat across regions and gas users.¹

Similarly, voluntary information from producers highlights that it is too early at this stage to know whether the trends in demand observed in the first five months of 2020 will continue, or if the contraction in economic activity brought about by the COVID-19 pandemic will result in a decline in domestic and/or international demand for gas in 2021.

We will continue to monitor the effects of COVID-19 on demand and will revisit the 2021 demand-supply outlook in our next report.

Compared to the supply outlook for 2020 at this point last year (and using the latest AEMO demand estimates and production forecasts provided by producers to the ACCC in May 2020) east coast supply is expected to be 13 PJ lower and demand 40 PJ lower in 2021. In total, the supply outlook for 2021 is less tight than forecast for 2020.

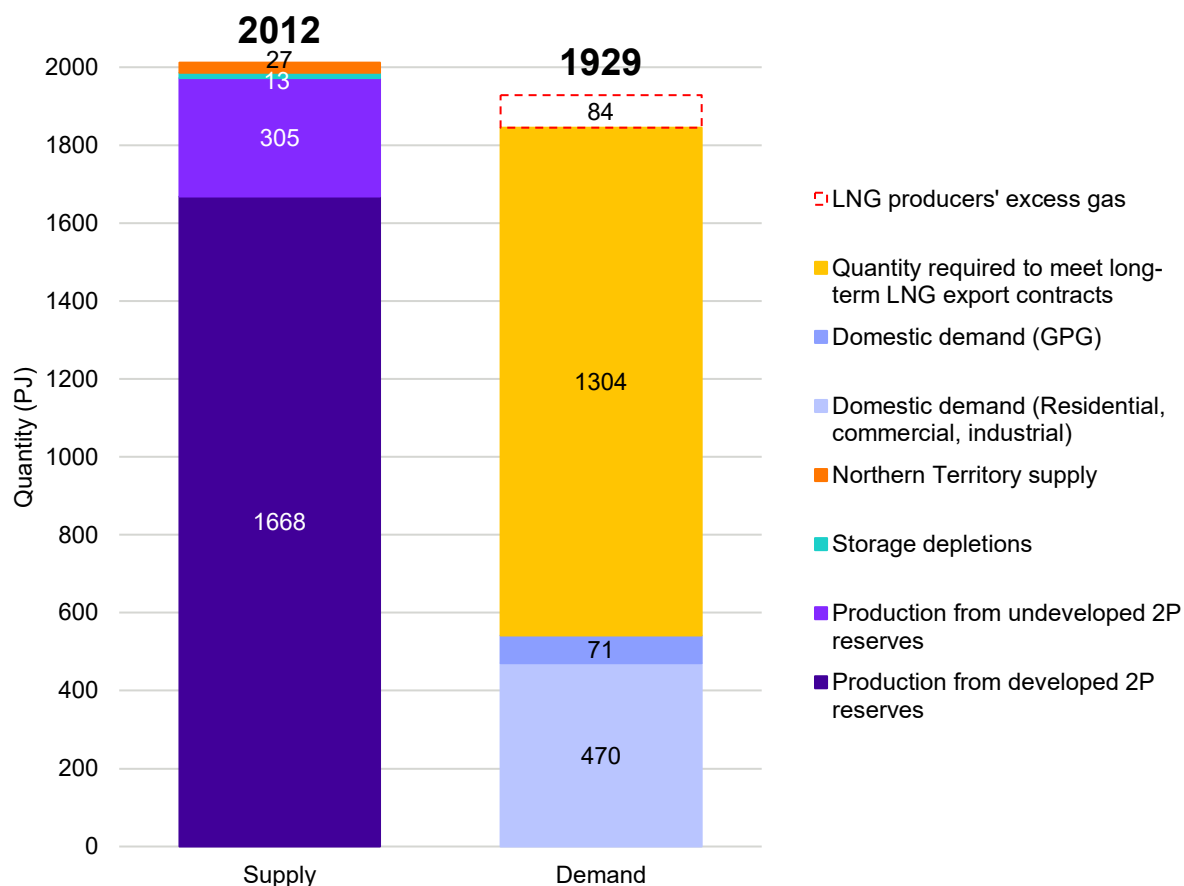
Chart 1 shows that overall, 1973 PJ of gas is forecast to be produced in 2021 and LNG producers expect to have 84 PJ of gas available in excess of their domestic and export commitments, which could either be exported or sold to the domestic market. The LNG producers are also forecasting to contribute more to the domestic market (214 PJ) than they expect to take out (173 PJ).

However, this is subject to some uncertainty. Firstly, demand for gas for GPG is highly volatile year-on-year and is difficult to forecast. As noted above, there is also now a considerable degree of uncertainty surrounding the demand for gas by other gas users following the COVID-19 pandemic and the impact this has had on economic activity, both domestically and internationally.

Secondly, and of greater concern, the supply of gas in 2021, particularly in the southern states, is heavily reliant on production from undeveloped 2P reserves, as shown in Chart 1.

¹ Demand for gas by gas powered generators (GPG) was lower over the first five months of 2020 compared to 2019, particularly in the south, while the demand for gas by LNG exporters and other domestic users was higher.

Chart 1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2021



Source: ACCC analysis of data obtained from gas producers as at May 2020 and of the domestic demand forecast (central scenario) from AEMO's March 2020 GSOO.²

Note: Totals may not add up due to rounding. Total demand includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments for 2021. This gas could either be exported or supplied to the domestic market.

On current expectations supply for 2021 exceeds demand expectations. However, based on previous years, we expect these two measures to move closer together over time such that ultimately supply will be equal to demand, as the market adjusts.

Significantly, 21 per cent of production (78 PJ) in the southern states (excluding the Cooper Basin) is expected to come from undeveloped 2P reserves. This is far higher than what we observed for 2020 at this point last year, when 8 per cent of southern states' forecast production was expected to come from undeveloped 2P reserves.

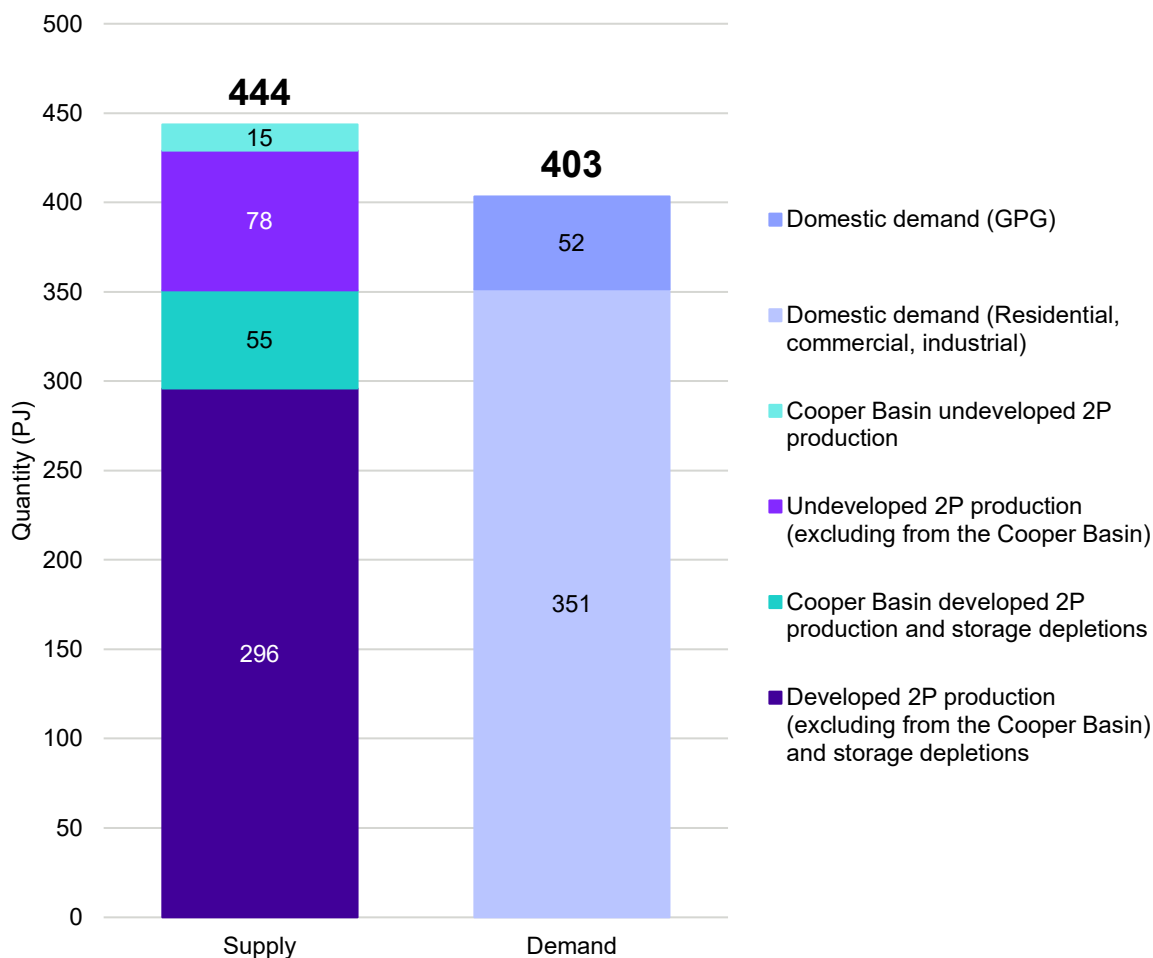
Before production of these undeveloped reserves can occur, additional work and investment will be required, such as drilling new wells on undrilled acreage, deepening existing wells to a different reservoir, infill wells and other relatively large expenditures.³ There is a risk therefore that the development of these reserves could be delayed or deferred, either as a result of technical difficulties or capital constraints, with the latter posing a greater risk following the significant fall in oil prices and the effect COVID-19 has had on economic activity.

² AEMO, *Gas statement of opportunities*, March 2020. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

³ Society of Petroleum Engineers (SPE), *Petroleum resources management system (PRMS)*, June 2018, p. 34.

While supply is forecast to be sufficient to meet demand in the southern states, and across the east coast as a whole, if there is any delay in the 78 PJ of undeveloped 2P reserves being brought online, then a shortfall in the south could arise in 2021. If this occurs, greater volumes of gas may need to be supplied by the LNG producers into the southern states, rather than being sold as spot cargoes.

Chart 2: Forecast domestic supply-demand balance in the Southern states for 2021 (including a proportion of Cooper Basin gas)



Source: ACCC analysis of data obtained from gas producers as at May 2020 and of the domestic demand forecast (central scenario) from AEMO's March 2020 GSOO.⁴

Note: Totals may not add up due to rounding. Moomba storage depletions are included with Cooper Basin developed 2P production, and Newcastle storage depletions are included with developed 2P production from the southern states excluding from the Cooper Basin.

For the first time in this Inquiry, we have examined actual production levels against production levels forecast by producers.

We have found that overall production levels in 2017 and 2018 were significantly below forecast. This appears to have been driven by the LNG producers, who produced between 68 and 70 PJ less than forecast in these years. These outcomes appear to have reversed in 2019, however, with LNG producers producing about 40 PJ more than forecast (while southern state producers produced 21 PJ less than forecast). This occurred in a context where GPG demand for that year was almost double AEMO's GSOO forecast and overall demand in the East Coast Gas Market for 2019 was significantly higher than forecast. At the

⁴ AEMO, *Gas statement of opportunities*, March 2020. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

same time, LNG producers also contracted to supply an additional 18 spot cargoes into international markets.

The response of the LNG producers to increased domestic demand in 2019 highlights their ability to divert gas into the domestic market when required, and suggests Queensland gas could meet forecast demand should risks associated with southern states' production arise.

What prices such supply is offered at is, however, an important consideration and discussed further below, as is access to the key pipelines required to move gas south and the prices charged by these pipeline operators.

The capacity of LNG producers to seemingly increase domestic supplies to keep the East Coast Gas Market supplied with just enough gas may also point to broader competition and market power concerns.

Softening domestic prices are significantly above export parity prices and the prices LNG producers receive for overseas spot sales

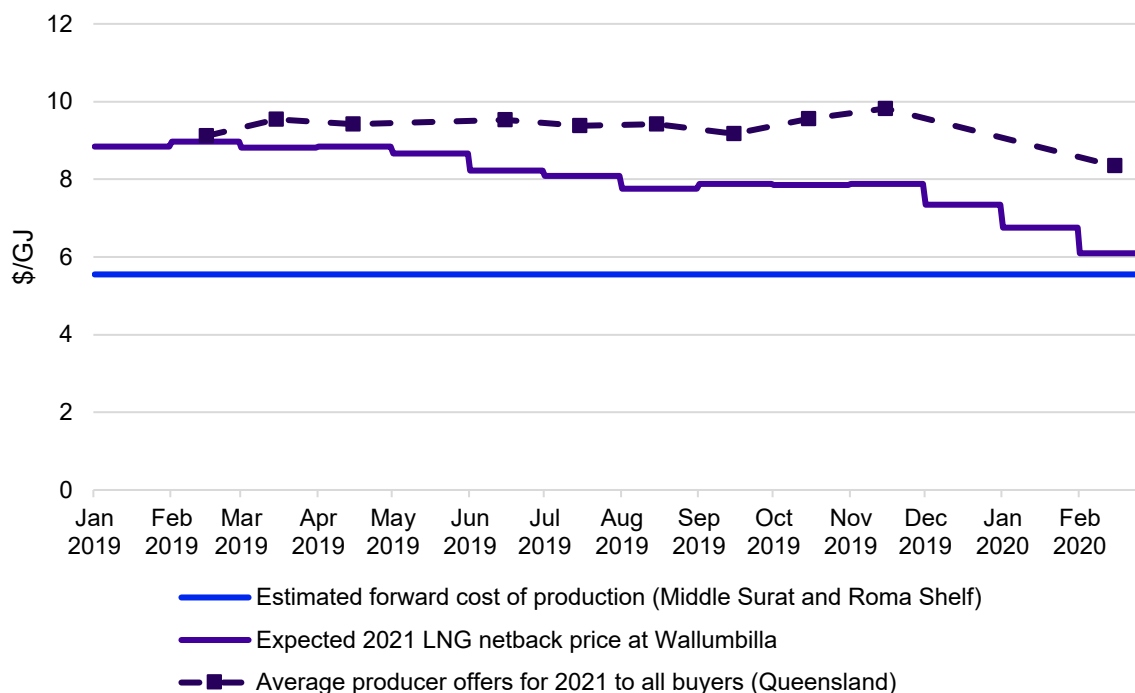
In recent months international oil and LNG prices have fallen drastically, both decreasing by over 40 per cent between January and May 2020. Similarly, expectations of international oil and LNG prices for 2021 have also fallen, both decreasing by over 25 per cent over the period. Reflecting changes in international LNG prices, LNG netback price expectations have fallen by around 25 per cent.

The range of prices offered for both 2020 and 2021 supply has softened slightly over the course of 2019 and early 2020. By the end of this period, most producer offers were in the range of \$8–10/GJ for 2020 and 2021 supply and most retailer offers were between \$9–11/GJ. When we reported in January 2020, the price ranges were \$9–10/GJ for producers and \$8–12/GJ for retailers.

Another positive sign that prices have softened is that prices agreed under newly executed gas supply agreements (GSAs) have reduced somewhat from a peak of just over \$10/GJ—this reflects a decline in fixed price GSAs and the recent collapse in oil prices flowing through to oil-linked GSA prices. This is particularly evident in the southern states.

Despite this softening, of increasing concern to the ACCC is the widening divergence between domestic prices offers and the LNG netback price. Domestic prices in Queensland now diverge from export parity LNG netback prices by more than \$2/GJ, as set out in Chart 3 below.

Chart 3: Averages of monthly gas commodity prices offered by Queensland producers for 2021 supply against contemporaneous expectations of LNG netback prices



Note: This chart shows expected average LNG netback prices in 2021 up to the end of February 2020. However, as shown in chart 2.4, expected average LNG netback prices in 2021 have fallen since February 2020, and by June 2020 were just above \$5/GJ.

Queensland prices for the first time in this Inquiry are also higher than they are in the south. This is most likely due to the higher prevalence of oil-linked pricing mechanisms in domestic GSAs entered into by suppliers in southern states.

Of even further concern is that since September 2019 there have been 18 LNG spot cargoes sold by Queensland LNG producers (with some of these cargoes to be delivered throughout 2020). These sales occurred after a period, from late December 2018, of no spot sales from the east coast of Australia. The prices received for these spot cargoes were roughly equivalent to or below Asian LNG spot prices at the time the sale was executed, and well below the prices being offered to the domestic market.

The spot cargo sales, together with the divergence that has occurred between LNG netback prices and domestic prices, also brings into question what is driving the pricing strategies of LNG producers and other suppliers in the East Coast Gas Market, and the extent to which it reflects a more fundamental lack of competition amongst suppliers.

Consistent with our previously stated priority of better understanding the divergence between domestic gas prices and LNG netback prices, we have issued the LNG producers and other key suppliers with compulsory information notices to obtain further information on their pricing strategies. We will closely examine this information and report on our findings and any consequential recommendations.

Little change in most gas transportation and storage prices, but emerging pressure points require attention

With some exceptions, firm transportation and storage prices are relatively unchanged since our last report. Standing prices published by most pipelines increased in line with inflation

between July 2019 and January 2020, as did the actual prices paid by most shippers. The implication of this is that the monopoly pricing we first observed in our 2015 East Coast Gas Inquiry has therefore continued.

The prices paid by users of the Dandenong LNG storage facility also increased in line with inflation, while the maximum price paid by users of the Iona storage facility increased.

The key exceptions to this more general trend were the Tasmanian Gas Pipeline (TGP), where the minimum price paid by shippers fell by 13 per cent and the two pipelines servicing South Australia, where the maximum prices paid by shippers on both the MAPS and the Port Campbell to Adelaide (PCA) pipeline increased by 15 per cent.

The price increases observed on the MAPS and PCA are in addition to the increases we observed in our July 2019 report, with prices on the PCA rising by 61 per cent over the period July 2018 to January 2020, while the maximum price on the MAPS rose by 17 per cent over the same period. The level of these increases is concerning and suggests that competition between these two (separately owned) pipelines servicing Adelaide is not as effective in driving prices down to a cost-reflective level as might be expected. This was also borne out in both our July 2019 review of the information published by the two pipeline operators under Part 23 of the National Gas Rules (NGR), and our January 2020 review of the prices charged by the two pipeline operators for capacity trading and the day-ahead auction.

The behaviour observed in South Australia, along with the continuation of monopoly pricing we first observed in our 2015 East Coast Gas inquiry, highlights the importance of the reforms that are currently being contemplated as part of the COAG Energy Council's Options to improve gas pipeline Regulation Impact Statement (RIS), which if implemented would strengthen the threat of a stronger form of regulation being applied to these two pipelines. One of the more significant reforms that is being contemplated, which we agree with, is that the coverage test (which is akin to the declaration criteria in Part IIIA of the *Competition and Consumer Act* (2010)) would be removed from the regulatory framework and decisions about the form of regulation would be based on the degree of market power possessed by the pipeline operator. The other important reform that is being considered, which we also agree with, is that the regulator would play a greater role monitoring the behaviour of pipeline operators. If the regulator formed the view that market power was or could be being exercised then the regulator could refer a pipeline to the relevant decision maker to determine if a stronger form of regulation should apply to that pipeline.

As part of our review, we have examined the access requests received by pipeline operators and the offers they have made between March 2019 and February 2020. We have found that while most contract negotiations take approximately 1–2 months between an access request first being made and an agreement being entered into, the negotiation period can be substantially longer if the pipeline needs to be extended, expanded or otherwise modified to accommodate the shipper's requirements.

While this finding is not surprising, it does highlight one of the risks in relying on more gas being able to flow from Queensland into the southern states relatively quickly, given the Wallumbilla compression facility, the SWQP and MAPS are fully, or close to fully, contracted and, in the case of the MAPS, experiencing physical constraints. If a shipper or producer in the north is unable to obtain timely access to key north-south pipelines in order to transport gas to the southern states, then the risk that a shortfall could arise is increased.

A related concern is the length of time that GTAs operate for and whether they are sufficiently long to underwrite the investment that would be required to increase north-south transportation infrastructure. Our examination of recently executed GTAs indicates that most GTAs having a contract term of 1–3 years. While this is longer than the contract terms we observed the last time we examined this issue, it is considerably shorter than the 10 to

15 year terms that are usually required to underwrite a major expansion or development of a new pipeline.

The relatively short contract terms for new GTAs is consistent with what we have observed with new GSAs and highlights that if buyers and/or suppliers are unwilling to commit to longer contract terms, then the investment required to avoid potential shortfalls in the southern states may not occur.

Policy challenges and recommendations

As we identified in our January 2020 report, the southern states risk facing a shortfall in the medium term unless:

- more production and development occurs in the south to compensate for declining production in the Gippsland Basin
- more investment occurs in north-south transportation infrastructure and/or
- one or more import terminals are developed.

The risk of a shortfall, particularly in the south, now appears even greater following the significant fall in oil prices and the increasing reliance that producers are placing on supplying gas from undeveloped reserves.

The risk of a shortfall in the east coast gas market overall highlights the relevance of the HoA the Commonwealth Government has with LNG producers. The HoA is currently due to expire at the end of 2020. It is important to note that a HoA on its own is unlikely to be enough to adequately address the supply risks the East Coast Gas Market faces and that further measures will be required.

In this regard, we note that various governments have announced a range of measures designed to increase the supply of gas into the domestic market over the medium to longer term. These include:

- the Victorian Government's decision to end its moratorium on onshore conventional gas development from 1 July 2021 and to release more acreage
- the Queensland Government's decision to release more acreage for domestic supply
- the Commonwealth Government's decision to release more offshore acreage
- the NSW and Commonwealth Government's Energy Package Memorandum of Understanding, which, amongst other things contains a target to increase the supply of gas from NSW by 70 PJ per annum by 2022.

We emphasise, in particular, that the removal of the moratoria and the release of new acreage is likely to only lead to improvements in supply in several years' time. When coupled with the uncertainty surrounding oil and gas prices and their impacts on investment, it is far from certain new supply will eventuate, either in time to avert the potential future shortfalls or in the volumes initially estimated. We also note that due to the long lead times between potential gas resources being identified and their development, the range of solutions to address the potential gas shortfalls will substantially narrow the closer we get to 2024.

In respect of tenement ownership and release of new acreage, we note that we will examine the concentration of tenements and the competitiveness of supply across the domestic market in 2021. As part of this examination, we intend to consider whether measures, such as targets or an explicit requirement to consider the share of gas resources held by a producer when granting new tenements, are required to encourage greater diversity of suppliers, noting that greater competition among suppliers should place downward pressure on prices.

Limited improvement in the pricing of gas transportation services and emerging areas of concern in South Australia also highlight the importance of the reforms currently being contemplated as part of the COAG Energy Council's Gas Pipeline RIS and the need to strengthen the threat and effectiveness of gas pipeline regulation.

Previous ACCC recommendations

1. Consistent with the observations contained in our earlier reports, we recommend that when releasing any new acreage, governments pursue greater diversity of suppliers. We also continue to recommend that governments use measures such as active tenement management to ensure producers bring gas to market in a timely manner and to prevent larger producers from 'warehousing' gas.
2. In our January 2020 report, we recommended that, where feasible, state governments coordinate the development of pipeline and storage infrastructure to avoid unnecessary duplication of pipelines and other inefficiencies, and to ensure infrastructure is operated on a third party access basis. Our most recent examination continues to support this recommendation.

New ACCC recommendations

1. To address the risk of a potential shortfall in the East Coast Gas Market in the short term, the ACCC recommends that the Commonwealth Government extend its HoA with the LNG exporters.

We also suggest the Government also consider strengthening the commitments in the HoA around the pricing of offers to domestic gas users in the HoA, so that there is more clarity around what is meant by 'competitive market terms'. This could, for example, refer to the relevant LNG netback price expectations and the prices the LNG exporters could expect to receive in overseas spot markets for the relevant supply period—that is, their opportunity cost of selling the gas into the domestic market.

2. Governments consider whether further measures are needed to ensure that north-south transportation infrastructure or import terminal investment on the east coast occurs in time to avoid potential supply shortfalls.

Future work of the Inquiry

The ACCC expects to provide its next interim report in late 2020/early 2021.

We will provide updates on:

- the prices offered and agreed for gas supply for 2021
- the gas supply outlook for 2021 and the longer term outlook to 2032
- the C&I gas user experience, and
- the pricing of transportation and storage services.

As already flagged, our priorities over the next 12–18 months will be:

- analysis of the pricing strategies of gas suppliers and a better understanding of the increasing divergence between domestic gas prices and the LNG netback, and
- an examination of concentration of tenements and the competitiveness of supply across the domestic East Coast Gas Market.

We continue to monitor competition in retail and wholesale markets and will provide further commentary and analysis as appropriate.

We also continue to:

- publish the LNG netback series on our website
- make information available and policy recommendations where we consider it appropriate and necessary to do so.

1. Supply and demand outlook

1.1. Key points

- Early 2020 saw the onset of the COVID-19 pandemic and a collapse of oil and LNG prices to record low levels. While the full effect of the pandemic is not yet clear, it is expected to affect both the supply of and demand for gas in 2020 and beyond. The fall in oil and LNG prices, while bringing some short-term relief to domestic gas users, has increased the supply risks facing the gas market over the medium to long term.
- Despite the uncertainty created by these events, east coast gas supply is currently expected to be sufficient to meet forecast domestic and export demand in 2021.
- However, uncertainty is heightened because the east coast is expected to be more reliant on production from undeveloped 2P reserves in 2021 than it was for 2020. Development of these reserves will require significant investments which producers may be less able or willing to undertake in a low oil price environment. Around 21 per cent of production in 2021 in southern states is expected to come from undeveloped 2P reserves.
- Sufficient gas is expected to be produced in the southern states to meet demand. However, the supply-demand balance in the south for 2021 remains tight and is subject to a large proportion of undeveloped 2P reserves being developed and demand for GPG being at record low levels. If this does not occur the southern states may need additional gas to flow south from Queensland.
- LNG producers in Queensland expect to have 84 PJ of gas available in excess of their domestic and export commitments in 2021, which could either be exported or used to supply the domestic market. The LNG producers currently expect to be net contributors to the domestic market.
- While there are increased risks to the supply outlook, there have also been some positive developments which should increase supply over the longer term. These include the commitment by the Commonwealth and NSW governments to inject more gas into NSW, and the decision by the Victorian government to lift the moratoria on onshore conventional natural gas exploration.
- Comparative analysis of forecast and actual gas production over 2017–2019 shows that LNG producers in Queensland produced between 68 and 70 PJ less than forecast in 2017 and 2018. However, this reversed in 2019, when they produced about 40 PJ more than forecast while producers in the southern states produced 21 PJ less than forecast. This is consistent with two key trends over 2017–2019, where:
 - Queensland production has grown by 11 per cent from 1274 PJ to 1406 PJ
 - Southern production has fallen 21 per cent from 442 PJ to 349 PJ.
- With lower than expected southern production in 2019 coinciding with higher than expected southern demand, the LNG producers' response highlights their ability to divert gas into the domestic market when required. With an increased reliance on undeveloped 2P reserves in 2021, the need for this may be even greater.
- However, the capacity of LNG producers to seemingly increase domestic supplies to keep the East Coast Gas Market supplied with just enough gas may also point to broader competition and market power concerns.

1.2. The impact of COVID-19 and low oil and LNG prices is unclear, but the effects may reverberate for some time

The East Coast Gas Market was hit by two major exogenous shocks in early 2020: the COVID-19 pandemic and record low oil and LNG spot prices.

The COVID-19 pandemic has affected economic activity both domestically and internationally. While the full effect of the pandemic on the economy is not yet clear, the changed conditions can be expected to affect both the supply of, and demand for, gas in the East Coast Gas Market in 2020 and beyond.

At the same time, the market has also seen a rapid decline in oil and LNG spot prices. Brent Crude oil prices, for example, fell from a high of US\$70/bbl in early January to a record low of US\$9/bbl on 21 April 2020⁵, in response to COVID-19 (prompting a collapse in global demand for oil) and decisions by Russia and Saudi Arabia to increase oil production. While prices have recovered somewhat following the decision by OPEC+ to cut production, they remain at relatively low levels, with the Brent Crude oil price at the end of May being around US\$34/bbl.⁶

In a similar manner to oil, LNG spot prices in Asia fell by around 66 per cent between January and April, but recovered somewhat in May (see section 2.3 for more detail). While the fall in oil and LNG spot prices has brought some short-term price relief to domestic gas users (see section 2.6), it has also increased the risks surrounding the adequacy of supply in the east coast over the medium to long term, because it reduces the ability of producers to invest in exploration and new developments.

Importantly, the effect on investment is not limited to gas producers that have direct exposure⁷ to oil or LNG spot prices and are now generating less revenue. Rather, it can affect all gas producers, because low oil and LNG spot prices can be seen by potential investors as a sign of low future gas prices. Producers that require finance to fund exploration and development may therefore find it difficult to do so in a low oil and LNG price environment.

To understand the effect that COVID-19, low oil and LNG spot prices have had on the East Coast Gas Market to date, we have examined a number of supply and demand indicators. We have also asked participants in our commercial and industrial (C&I) user survey about the effect the pandemic has had on their demand for gas, and sought information from suppliers regarding the changes that they have observed to date.

Based on this examination it appears that:

- overall, levels of production and consumption in the East Coast Gas Market have not been materially affected in the first five months of 2020. However, this differs somewhat across regions and gas users, and it is unclear whether this trend will continue
- a number of producers have already responded to low oil and LNG spot prices by cutting upstream expenditure and delaying the development of some projects. This is concerning and may mean that the risk of a shortfall arising in the medium term is greater than previously expected.

⁵ U.S Energy Information Administration, 'Europe Brent Spot Price FOB' series

⁶ Ibid.

⁷ A producer may have direct exposure if they produce oil or LNG, or have oil or LNG-linked GSAs.

1.2.1. COVID-19 appears to have had little effect on the East Coast Gas Market so far

Over the first five months of 2020, production across the east coast⁸ was 0.4 per cent *higher* than it was over the same period in 2019 (762 PJ versus 759 PJ),⁹ while storage levels were on average 0.8 per cent *lower* than over the same period in 2019 (98 PJ versus 99 PJ).^{10,11}

At a regional level, production was three per cent (17 PJ) higher in Queensland and 19 per cent higher (7 PJ) in the Cooper Basin.¹² Production in the southern states, on the other hand, was 17 per cent (21 PJ) lower than over the same period in 2019. This may, in part, reflect lower GPG demand in the south (see below). It may also reflect the general decline in production from the Gippsland Basin that has been observed over the last three years (see section 1.8.2), with production from this basin accounting for the majority of the fall.¹³

Similarly, overall consumption of gas in the east coast was largely unchanged over the first five months of 2020 relative to 2019. While a full breakdown of consumption is not currently available, it appears from a range of indicators that the effect on consumption has differed somewhat across sectors and regions:

- LNG exports were 1.3 per cent (6.5 PJ) *higher* in the first five months of 2020 than they were over the same period in 2019.¹⁴
- GPG demand was 23 per cent (16 PJ) *lower* over the first five months of 2020 than it was over the same period in 2019, with southern states GPG demand 36 per cent (18 PJ) lower and Queensland GPG demand 9 per cent (2 PJ) higher.¹⁵
- C&I demand on an aggregate basis appears to have been relatively stable, although some respondents to our C&I user survey noted they had used more gas in the initial stages of the pandemic in response to the increase in demand for their end products (e.g. food products), while others used less (see section 3.3 for more detail).¹⁶

It is unclear whether the trends in demand observed to date will continue over the remainder of 2020, or if the contraction in economic activity brought about by the COVID-19 pandemic will result in a decline in the demand for gas in 2021.

This view is consistent with views expressed by suppliers contacted by the ACCC; most noted it was difficult to predict what would occur given we are still in the midst of the pandemic and significant uncertainty surrounds its impact on domestic and international economic activity. While expressing caution about trying to predict what would occur, most suppliers indicated in early June 2020 that while they expect some reduction in domestic and international demand, they did not expect it to be significant. Most suppliers, for example,

⁸ Note that references to production in this section exclude production from the Northern Territory because the Bulletin Board does not have information on the amount of gas produced in the Northern Territory or supplied into the east coast between January 2019 and 8 April 2019. It has not been possible therefore to compare the production levels over an equivalent time frame.

⁹ Based on Actual flow and storage data obtained from the Bulletin Board for the period 1 January 2019 to 31 May 2020, <https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-portal>

¹⁰ Ibid. Note this calculation is based on the average volume of gas held in storage in each month over the relevant periods.

¹¹ The quantity of gas held in the Moomba, Silver Springs and Dandenong storage facilities was lower in the first five months of 2020 than it was in 2019, while the amount of gas held in the Iona, Roma and Newcastle storage facilities was higher.

¹² Bulletin Board actual flow and storage data <https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-portal>

¹³ Ibid.

¹⁴ Based on trade statistics data published by Gladstone Ports Corporation <https://www.gpcl.com.au/trade-statistics>

¹⁵ The GPG demand data is based on the AER's analysis of National Electricity Market data. <https://www.aer.gov.au/wholesale-markets/wholesale-statistics/average-daily-gas-used-for-gas-powered-generation>

¹⁶ Note that there is currently no publicly available information on C&I demand, so these observations are based on the feedback provided through the C&I user survey (see section 3.3). It is worth noting though that this observation is consistent with that made by EnergyQuest in its June 2020 report. See EnergyQuest, EnergyQuarterly, June 2020, p. 25.

informed us that while there had been some reductions in gas nominated by domestic buyers under GSAs, demand was not expected to fall below GSA take or pay levels in 2020 or 2021.

A number of suppliers told us they expect GPG and C&I demand to be lower in 2020. Residential demand, on the other hand, is expected to be higher than usual, particularly during the winter months, with more people working from home. This view is consistent with analysis recently carried out by AEMO, which suggests residential demand in Victoria will be 2 per cent higher on mild days and 7 per cent higher on very cold days.¹⁷

Regarding LNG exports, Santos and Origin's announcements earlier this year that some LNG buyers had exercised downward quantity tolerance provisions in their contracts suggests that exports under long-term LNG supply contracts will be lower.¹⁸ While it is possible that some of the gas that would otherwise have been sold under these contracts may still be exported on a spot basis, LNG producers have told us they expect to use a range of other measures to manage any excess supply. This could include turning down wells, placing more gas into storage and taking less gas under either third party GSAs or joint venture arrangements.

There are indications that some of these measures are already being implemented. Average storage levels in GLNG's Roma Underground Storage facility, for example, increased by around 10 per cent between January and the end of May 2020. Senex also recently announced that it would redirect around 1 PJ of gas from the Roma North project, which is usually used to supply GLNG for export, to the domestic market.¹⁹ Other producers have also informed us that LNG producers have reduced the amount of gas they are taking under their third party GSAs.

1.2.2. Low oil and LNG prices are already affecting upstream investments, which could affect the availability of supply over the medium-term

Following the sharp fall in oil and LNG spot prices, a number of producers have announced significant reductions in capital expenditure and delays to some projects. While the effects of these changes are in most cases expected to affect supply over the medium-term, a small number of producers have informed us that it may also affect production in 2021.

Some of the more notable announcements that have been made include Beach Energy's²⁰ announcement that it intends to reduce capital expenditure by around 30 per cent²¹ and Origin Energy's announcement that it is targeting a \$300–\$400 million reduction in APLNG's upstream capital expenditure.^{22,23} Origin has also stated that it would 'temporarily pause'

¹⁷ AEMO, Victorian gas demand impacts from COVID-19 (News article), 12 May 2020.

¹⁸ Origin, Quarterly Report March 2020, 30 April 2020, slide 5 and Santos, First Quarter Activities Report, 23 April 2020, p. 4.

¹⁹ Senex, Senex and GLNG to supply Roma North natural gas to the domestic market; Senex FY20 guidance upgraded, 26 May 2020.

²⁰ Beach Energy, Business update, 27 March 2020.

²¹ Armour Energy has also announced that it will reduce and, where possible, defer its planned exploration and capital expenditures for 2020. Armour Energy, COVID-19 Response: Cost Reductions and Management Update, 27 April 2020. Santos has also announced that it will reduce capital expenditure by 40 per cent, although a large proportion of this appears to relate to the Barossa and PNG LNG expansion projects. Santos, COVID-19 Response and Business Update, 23 March 2020.

²² Origin Energy, Beetaloo Exploration Program update, 26 March 2020.

Santos, COVID-19 Response and Business Update, 23 March 2020.

²³ Origin Energy, Operational and financial update, 6 April 2020.

To put this into context, it is worth noting that in its 2019 annual report, Origin stated that total APLNG expenditure (including both capital and operating expenditure) in 2020 was expected to be \$2.8–\$3 billion. See Origin Energy, 2019 Annual Report, p. 20.

exploration in the Beetaloo Basin²⁴, while Central Petroleum has announced that it would ‘pause’ development of the Range project it is developing with Incitec Pivot in Queensland.²⁵

In response to ACCC queries on the effect of low oil prices, a number of other non-ASX listed producers informed us that they intend to reduce expenditure and suspend some aspects of their exploration and development programs.

In contrast, Senex and Galilee Energy, have announced that their operations will face minimal, or no changes in light of the recent decline in oil prices.²⁶ A number of producers have also confirmed they intend to proceed with the development of key projects that were expected to come online in 2021. Esso, for example, has announced it still intends to bring the West Barracouta project online in 2021.²⁷ Arrow Energy has also announced that it intends to proceed with development of the first phase of the Surat Gas Project.²⁸

Section 1.7 provides further detail on these announcements and other recent developments.

1.3. Supply is expected to be sufficient in 2021, however significant uncertainty remains

1.3.1. East coast supply-demand outlook for 2021

The supply and demand outlook for the East Coast Gas Market in 2021 indicates sufficient supply is expected to meet forecast domestic and export demand. Compared to the forecast for 2020 published in the ACCC’s July 2019 interim report, east coast supply for 2021 is expected to be 16 PJ lower and demand (including the LNG producers’ excess gas) is expected to be 70 PJ lower. That is, the supply-demand outlook for 2021 is expected to be less tight compared to the supply-demand forecast for 2020.

However, uncertainty around the adequacy of supply is heightened as the east coast is growing more reliant on less certain sources of supply.²⁹ This is apparent in the increased expected reliance on production from undeveloped 2P reserves for 2021, particularly in the southern states. Development of these reserves will require significant investments which producers may be less able or willing to undertake in a low oil price environment. This is discussed further in section 1.3.2.

Chart 1.1 below shows the ACCC’s supply-demand outlook for 2021. It shows total forecast supply (production, storage depletions, and expected flows from the Northern Territory to the east coast) against total forecast demand (AEMO’s forecast of domestic demand plus the quantities of gas required by LNG producers to meet their long term export contract commitments).³⁰ The demand forecast includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments for 2021.

The supply and LNG contractual export demand data included in the chart below is based on information obtained directly from producers. The domestic demand forecast is based on

²⁴ Origin Energy, Beetaloo Exploration Program update, 26 March 2020.

²⁵ Central Petroleum, Operational Update, 27 March 2020.

²⁶ Senex Energy, Senex COVID-19 response and business update, 27 March 2020 and Galilee Energy Limited, Letter to Shareholders, 19 March 2020.

²⁷ Esso, Esso Australia drilling West Barracouta domestic gas wells, 6 March 2020. <https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2020/Esso-drilling-for-West-Barracouta-gas>; AFR, Exxon ‘pauses’ Bass Strait drilling, 15 April 2020.

²⁸ Arrow Energy, Start planned for Arrow’s Surat Gas Project, 17 April 2020.

²⁹ ACCC, Gas Inquiry 2017–2025 interim report, January 2020,

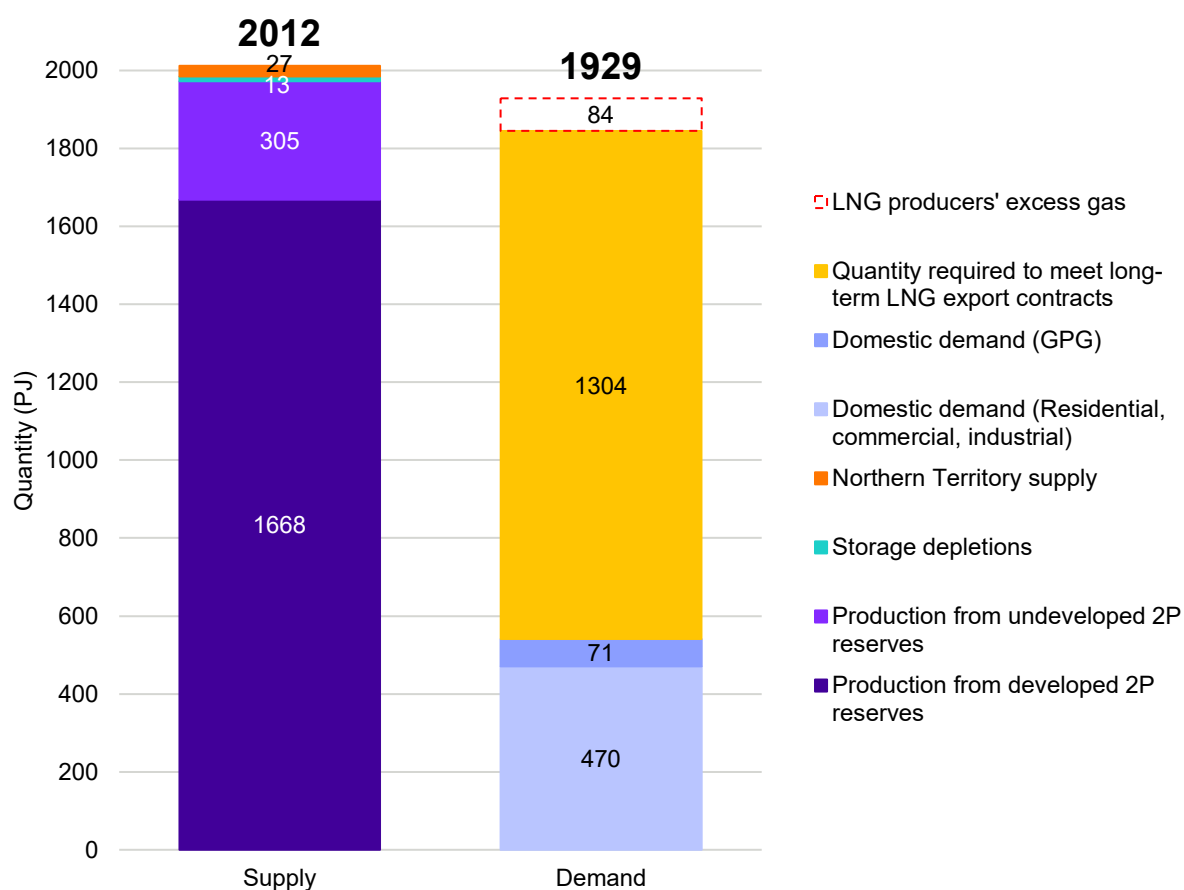
³⁰ Quantities required to meet long term LNG export contracts are based on LNG producers’ expectations as at May 2020. The quantity actually supplied under these contracts in 2021 may vary due to, for example, flexibility provisions in contracts, the execution of additional contracts or unexpected LNG plant maintenance.

AEMO's Central scenario from its March 2020 Gas Statement of Opportunities (GSOO).³¹ These demand forecasts, and some production forecasts provided to us by producers, were developed prior to the COVID-19 pandemic related shutdown that commenced in March 2020, and prior to the significant fall in oil prices.

As noted in section 1.2, while it appears that the pandemic has not as yet had a material effect on the overall level of production or consumption in the east coast gas market, it is still too early to know what the continued effects of the pandemic will be in 2021.

We will continue to monitor the effects of COVID-19 on supply and demand, and will revisit the 2021 supply-demand outlook in our next report.

Chart 1.1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2021



Source: ACCC analysis of data obtained from gas producers as at May 2020 and of the domestic demand forecast (central scenario) from AEMO's March 2020 GSOO.³²

Note: Totals may not add up due to rounding. Total demand includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments for 2021 (which could either be exported or supplied to the domestic market). While supply is currently expected to exceed demand, actual supply and demand are expected to converge by the end of 2021.

³¹ Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

³² AEMO, Gas statement of opportunities, March 2020. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

As noted above, compared to the supply-demand outlook for 2020 published in our July 2019 interim report, east coast supply for 2021 is expected to be 16 PJ lower and demand (including the LNG producers' excess gas) is expected to be 70 PJ lower. Combined, this means that the supply-demand outlook for 2021 is slightly less tight than the supply-demand outlook for 2020.

Supply outlook

On the supply side, the 16 PJ decrease reflects that production from 2P reserves is expected to be 21 PJ lower, while flows from the Northern Territory are expected to be 6 PJ higher, and storage withdrawals are expected to be slightly higher. Total production from 2P reserves in 2021 is expected to be a 1973 PJ, slightly lower than the 1988 PJ expected to be produced in 2020. Both of these figures exceed the 1910 PJ actually produced in 2019.

However, while east coast production from 2P reserves in total is expected to be lower in 2021 than for 2020, production from developed 2P reserves is expected to be 80 PJ lower, while production from undeveloped 2P reserves is expected to be 64 PJ higher. That is, the proportion of east coast production expected to come from 2P undeveloped reserves is expected to be significantly higher in 2021 than it was in 2020.

The proportion of production expected to come from undeveloped 2P reserves in a given year typically declines over time as forecast horizons shorten and producers undertake the activities required to convert them into developed 2P reserves. However, the increase in the proportion of production expected to come from undeveloped 2P reserves highlights a more uncertain supply outlook for the east coast in 2021 than has been the case in recent years. Section 1.3.2 provides more detail on this.

Chart 1.1 does not include production from contingent or undiscovered resources, which are highly uncertain. However, in addition to the production forecasts shown above, 22 PJ of gas is also forecast to be produced from contingent and undiscovered gas resources in 2021, which, if realised, could contribute additional quantities of gas to the east coast.

Currently, around 27 PJ of gas is expected to flow to the east coast from the Northern Territory in 2021, slightly above the 21 PJ expected for 2020. As the annual capacity of the Northern Gas Pipeline (NGP) is around 35 PJ, there is potential for additional gas from the Northern Territory to be transported to the east coast in 2021, assuming this gas is available.

Chart 1.1 also includes forecast storage withdrawals from the Roma, Moomba, Silver Springs and Newcastle storage facilities. Overall these facilities are expected to contribute 13 PJ of gas to the east coast in 2021. However, based on forecast storage levels, these storage facilities may be able to supply up to an additional 54 PJ of gas to the east coast, if necessary, in 2021.

Demand outlook

On the demand side, expected LNG export demand for 2021 is 9 PJ higher compared to 2020, continuing an upward trend (see table 1.1 below). In its March 2020 GSOO, AEMO noted that it expects this to continue in the short term, while in the longer term LNG export demand is forecast to remain at the level necessary to meet contractual obligations.³³ However, expected LNG demand could reduce below this level if buyers exercise downward quantity tolerance (DQT) rights for 2021 deliveries, as they have for 2020.

LNG producers currently expect to have 84 PJ of gas available in excess of their domestic and export contractual obligations in 2021. This gas, if produced, could either be exported or sold to the domestic market. Under the current Heads of Agreement between the LNG

³³ AEMO, GSOO, March 2020, p. 30.

producers and the Australian Government (due to expire at the end of 2020) uncontracted gas must first be offered to the domestic market on ‘competitive market terms’ before it is offered to the international market.³⁴ As outlined in the overview, the ACCC recommends that the HoA be extended beyond 2020 and that the government consider strengthening requirements around price offers.

Gas producers other than LNG producers expect to produce a total of 548 PJ in 2021. As at May 2020, these producers had contracted 242 PJ to retailers, out of 341 PJ contracted for supply in 2021 to domestic buyers. As shown in chart 1.3, as at May 2020 the LNG producers had contracted 214 PJ for supply in 2021 to domestic buyers, of which 131 PJ is contracted to gas retailers. Overall, around two-thirds of gas currently contracted for 2021 is contracted to retailers.

Compared to AEMO’s forecast for GPG demand in 2020, AEMO currently forecasts GPG demand in 2021 to be slightly lower while the other components of domestic demand (residential, commercial, industrial and losses), remain largely unchanged.

GPG demand is highly volatile and subject to large year on year changes. As shown in table 1.1, between 2017 and 2019, annual GPG demand in the east coast was between 46 PJ lower and 68 PJ higher than forecast. This high degree of variability reflects several factors, including the balancing role of GPG in the National Electricity Market, and the sensitivity of GPG demand to coal-fired generation outages and weather patterns. AEMO has recently observed that GPG forecasts are becoming increasingly uncertain.³⁵

GPG demand therefore remains a critical and highly uncertain component of expected demand in the east coast. The level of realised GPG demand could tighten the supply-demand balance in 2021 if it increases from the record lows forecast. This is particularly the case in the southern states, as discussed in section 1.5 below.

1.3.2. Uncertainty is heightened due to increased expected reliance on undeveloped 2P reserves

As noted above, the east coast is expected to be more reliant on undeveloped 2P reserves in 2021 than it has been in recent years.

The Petroleum Resource Management System (PRMS) defines undeveloped reserves as those requiring ‘significant additional investments’ (relative to the cost of drilling and completing a new well).³⁶ These investments can include drilling new wells on undrilled acreage in known accumulations, deepening existing wells to a different reservoir, infill wells and other relatively large expenditures required to recomplete an existing well, or to install production or transportation facilities.³⁷

Because of this need for additional investment, and the uncertainty of the performance of new wells, the ACCC has previously observed that production from undeveloped 2P reserves is less certain than production from developed 2P reserves.³⁸ Producers confirmed to the ACCC in June 2020 that the availability of capital for investment in drilling programmes, potential changes around the timing of drilling, and the performance of new wells are all risks that may impact production from undeveloped 2P reserves in 2021.

³⁴ Department of Industry, Innovation and Science, Heads of Agreement – the Australian east coast domestic gas supply commitment, 28 September 2018, <https://www.industry.gov.au/sites/default/files/heads-of-agreement-2018-prime-minister-and-east-coast-lng-exporters.pdf>.

³⁵ AEMO, GSOO, March 2020, p. 29.

³⁶ Society of Petroleum Engineers (SPE), *Petroleum resources management system (PRMS)*, June 2018, 2.1.3.6.1.B.

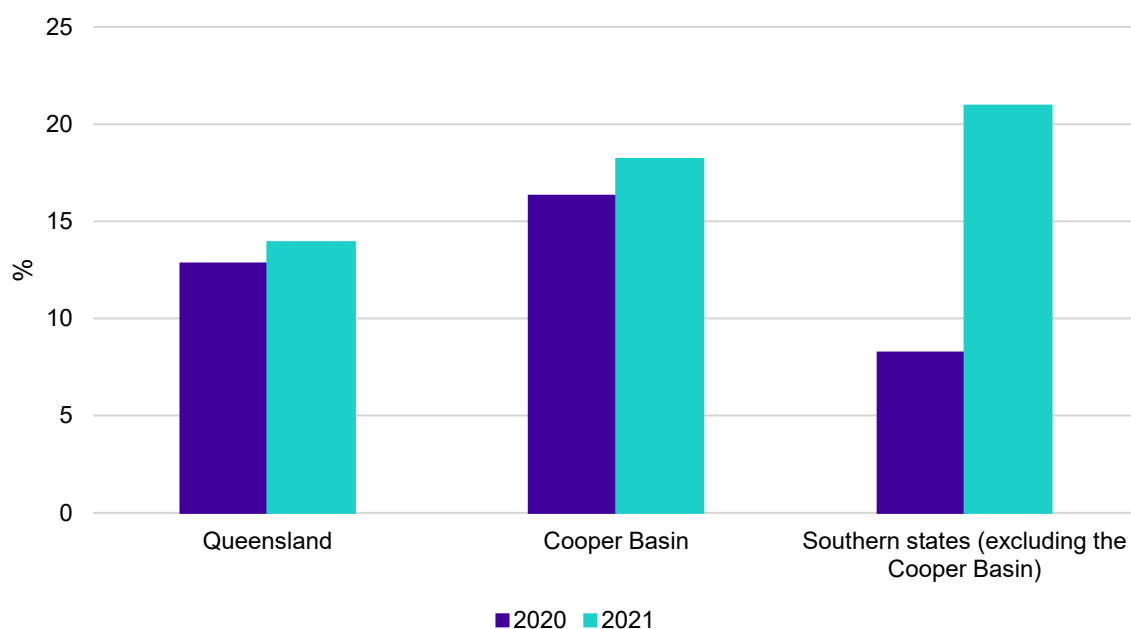
³⁷ SPE, *PRMS*, June 2018, p. 52.

³⁸ ACCC, *Gas Inquiry 2017-2025 interim report*, January 2020, p. 21; ACCC, *Gas Inquiry 2017-2020 interim report*, December 2018, p. 21.

Producers also informed the ACCC that a variety of additional factors may also pose risks to production from undeveloped 2P reserves in 2021. These include securing approvals and agreements (such as land access arrangements, environmental and other regulatory approvals, and internal joint venture partner agreement), delays in connecting new wells to existing infrastructure, and operational delays caused by weather impacts, equipment failure and the effect of the COVID-19 pandemic.

Chart 1.2 demonstrates how expected production from undeveloped reserves has changed between 2020 and 2021. It shows the level of production expected to come from undeveloped 2P reserves as a percentage of total 2P production for 2020 and 2021 in Queensland, the Cooper Basin and the southern states.

Chart 1.2: Proportion of total 2P production expected to come from undeveloped 2P reserves across east coast regions, 2020 and 2021³⁹



Source: ACCC analysis of data obtained from gas producers.

Note: Expected undeveloped and developed 2P production as at June 2019 (for 2020) and May 2020 (for 2021).

The percentage of total 2P production expected to come from undeveloped 2P reserves for a given year generally falls over time as the activities required to convert undeveloped reserves into developed reserves are undertaken by producers. This has been the case for production in both 2020 and 2021. For example, between August 2018 and May 2020, the percentage of total east coast production from 2P reserves expected to come from undeveloped 2P reserves in 2020 declined from 16 per cent to 4 per cent.

However, as shown in chart 1.2, expected production from undeveloped 2P reserves in 2021 is higher across all regions of the East Coast Gas Market when compared to expectations for 2020 at a similar point last year. This is particularly pronounced in the southern states, where expected production from undeveloped 2P reserves has increased from 8 per cent (for 2020) to 21 per cent (for 2021).

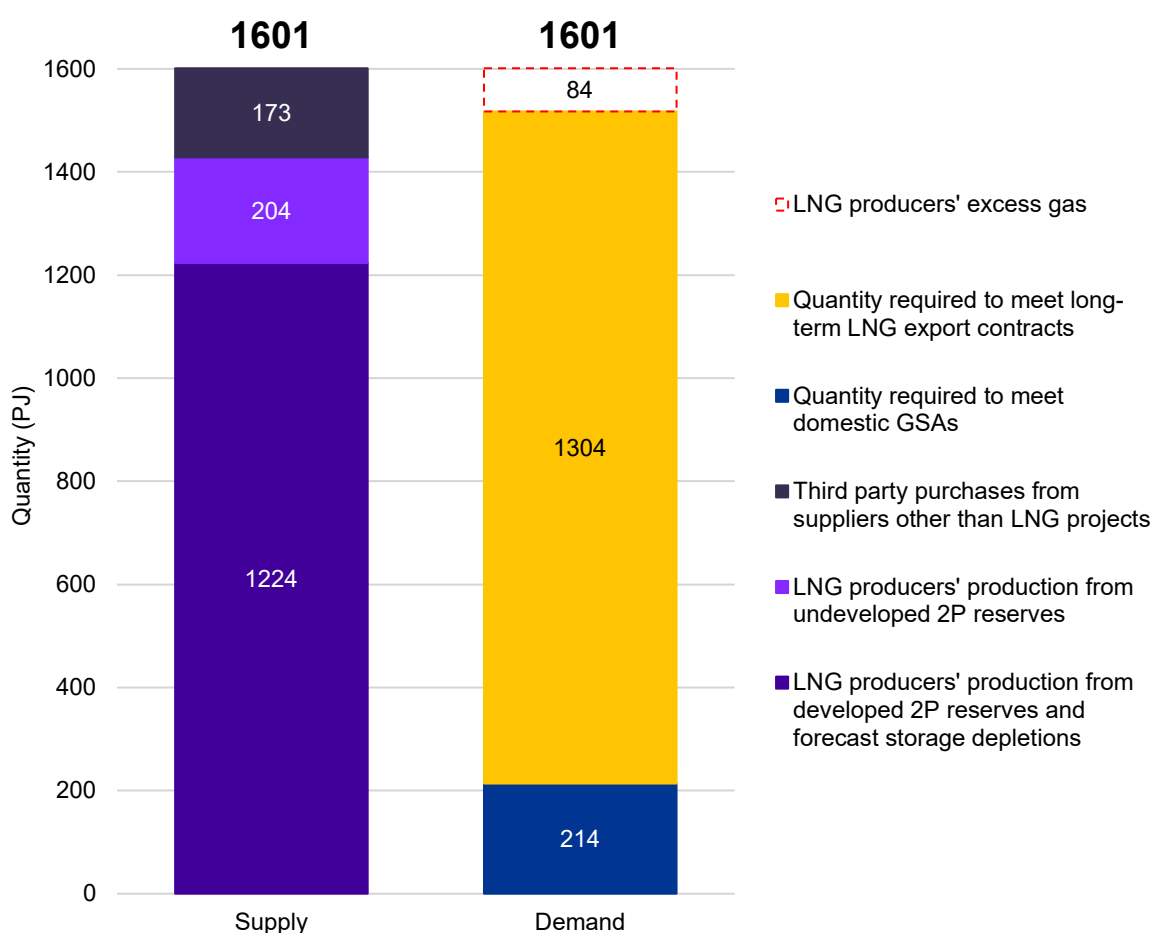
³⁹ Forecasts obtained as at August 2018 were published in the ACCC's December 2018 interim report, forecasts obtained as at June 2019 were published in the ACCC's July 2019 interim report, forecasts obtained as at August 2019 were published in the ACCC's January 2020 interim report, and forecasts obtained as at May 2020 are published in this report.

This is concerning given the tightness of the supply-demand outlook in the southern states (discussed in section 1.5 below) and the risks identified by producers as noted above, which are heightened due to the recent collapse in oil prices. As discussed further in sections 1.7.4 and 1.7.5 below, some producers in the Cooper Basin and the south, such as Beach Energy, have announced that they will be reducing or deferring capital expenditure. On the other hand, the commitment by Esso to develop the West Barracouta field is a positive sign that the percentage of total 2P production expected to come from undeveloped 2P reserves in 2021 may decline as 2020 progresses.

1.4. LNG producers expect to have enough gas to meet their domestic and export commitments in 2021

Chart 1.3 presents the expected supply-demand balance of the east coast LNG producers in 2021, based on information obtained directly from LNG producers by the ACCC.

Chart 1.3: Forecast supply-demand balance of east coast LNG producers in 2021



Source: ACCC analysis of data obtained from gas producers as at May 2020.⁴⁰

Note: Totals may not add up due to rounding.

Chart 1.3 shows that the LNG producers expect to have enough gas to meet their domestic and LNG contractual commitments in 2021.

⁴⁰ Quantities required to meet long term LNG export contracts are based on LNG producers' expectations as at May 2020. The quantity actually supplied under these contracts in 2021 may vary due to, for example, flexibility provisions in the contracts, the execution of additional contracts, or unexpected LNG plant maintenance.

Compared to the supply-demand balance for 2020 published in the ACCC's July 2019 interim report, the LNG producers' total supply is expected to be around 37 PJ lower. This reflects that third party purchases from suppliers other than LNG producers are expected to be 30 PJ lower, and production from 2P reserves and storage withdrawals are expected to be 7 PJ lower.

In aggregate, the LNG producers currently expect to contribute 214 PJ of gas to the domestic market, which is higher than the 173 PJ they expect to take out. This contrasts with expectations for 2020, when the LNG producers, in aggregate, expected to take out 203 PJ and contribute 176 PJ to the domestic market.

Compared to the forecast for 2020, the quantity of feed gas the LNG producers expect to require to meet their long-term LNG export contract commitments is 9 PJ higher, at 1304 PJ. As noted in section 1.3.1, this continues the trend of LNG export demand gradually increasing year on year. However, LNG contractual export demand in 2021 may decrease if DQT rights are exercised, which, as noted in section 1.2, they have been for 2020.

Taken together, the combination of lower expected gas supply and increased domestic and LNG contractual demand means that the LNG producers expect to have half the quantity of gas available in excess of their contractual commitments in 2021 compared to forecasts for 2020 (84 PJ versus 168 PJ).

As noted in section 1.3.1, if produced, the 84 PJ the LNG producers expect to have in excess of their contractual commitments in 2021 could be either exported or used to supply the domestic market. Supply to the domestic market should, in principle, be more attractive than exporting spot cargoes given current record low Asian LNG spot prices and prices being agreed under new domestic GSAs for 2021 supply (see section 2.5).

However, APLNG has been reported as considering whether to reduce production in order to reduce the quantity of gas sold on the LNG spot markets.⁴¹ This follows Origin Energy and Santos reporting that APLNG and GLNG's LNG buyers have exercised DQT rights for 2020, due to reduced LNG demand caused by the COVID-19 pandemic.⁴²

To the extent that production from undeveloped 2P reserves does not occur, the LNG producers may increase their reliance on third party gas. However, third party purchases from suppliers other than LNG producers are currently expected to be the lowest reported by the ACCC in this inquiry, and may reduce further with Senex Energy and GLNG recently announcing that 1 PJ would be redirected from GLNG to the domestic market.⁴³

1.5. The supply-demand outlook in the southern states for 2021 is less tight, but significant uncertainty remains

Chart 1.4 presents the expected supply-demand balance in the southern states for 2021. Forecast supply is based on data obtained directly from producers by the ACCC, and includes production from the Gippsland, Otway, Bass, Sydney and Gunnedah basins. Domestic demand is based on AEMO's forecasts.⁴⁴

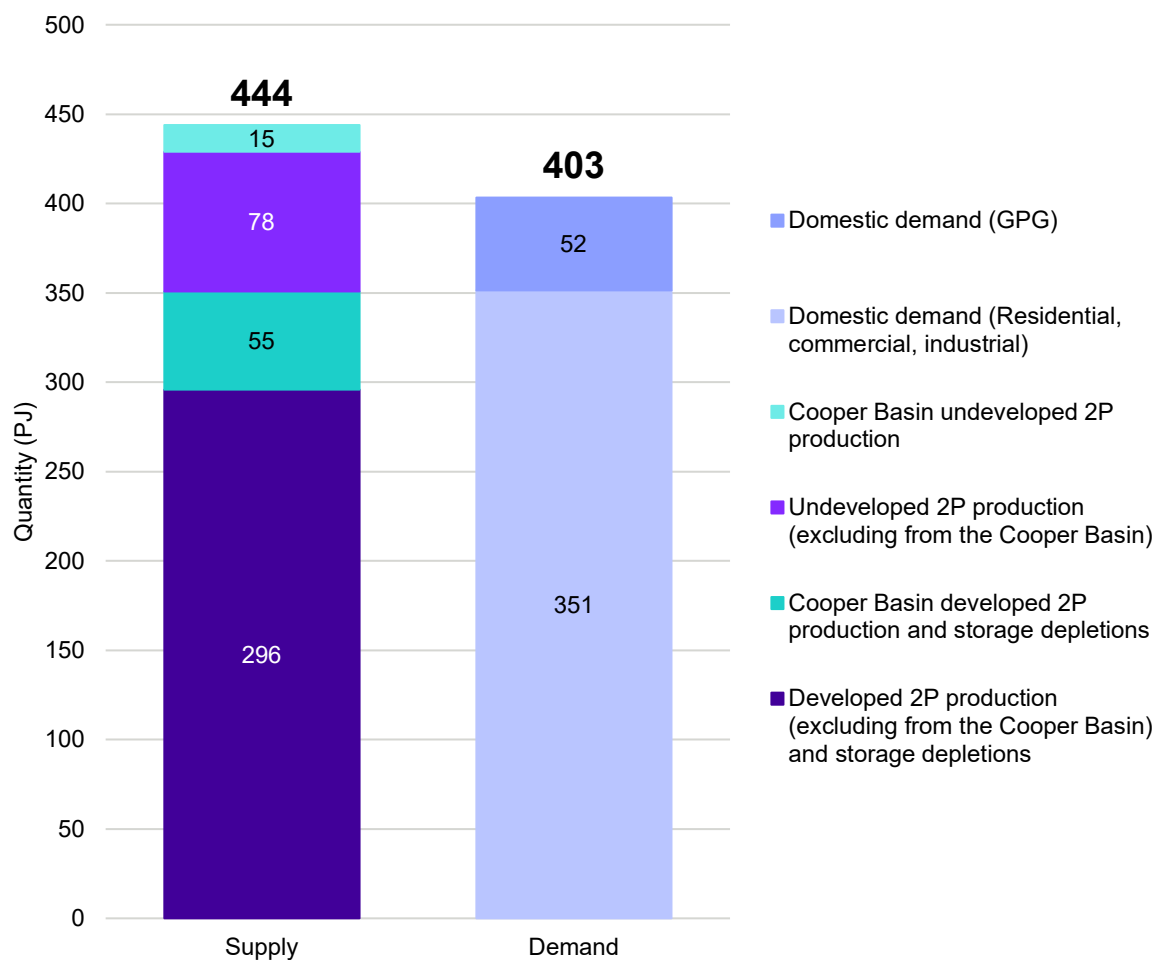
⁴¹ Reuters, 'RPT-Virus lockdowns pummel global gas demand, force LNG output cuts', 8 May 2020, <https://www.reuters.com/article/global-lng-costs/rpt-virus-lockdowns-pummel-global-gas-demand-force-lng-output-cuts-idUSL4N2CP1KJ>.

⁴² Origin Energy, *Quarterly report*, March 2020; Santos, *First quarter activities report*, 23 April 2020.

⁴³ Senex Energy, 'Senex and GLNG to supply Roma North natural gas to the domestic market; Senex FY20 guidance upgraded' (ASX Announcement), 26 May 2020.

⁴⁴ Specifically, domestic demand is based on AEMO's Central domestic demand scenario from its March 2020 Gas Statement of Opportunities.

Chart 1.4: Forecast domestic supply-demand balance in the southern states for 2021 (including a proportion of Cooper Basin gas)



Source: ACCC analysis of data obtained from gas producers as at May 2020 and of the domestic demand forecast (central scenario) from AEMO's March 2020 GSOO.⁴⁵

Note: Totals may not add up due to rounding. Moomba storage depletions are included with Cooper Basin developed 2P production, and Newcastle storage depletions are included with developed 2P production from the southern states excluding from the Cooper Basin.

Chart 1.4 shows that, compared to the 2020 outlook published in July 2019 the supply-demand balance is expected to be slightly less tight for 2021. This is due to the combination of expected southern supply being 6 PJ higher, while southern demand is forecast to be 5 PJ lower in 2021.

The southern states' expected supply-demand balance for 2021 is therefore the least tight of those reported by the ACCC over the course of this inquiry.⁴⁶ However, as discussed in section 1.3.2 above, the adequacy of supply in the south is heavily reliant on production from undeveloped 2P reserves, flows from the Cooper Basin and GPG demand remaining at a record low.

If GPG demand is higher than forecast, or if production from undeveloped 2P reserves and flows from the Cooper Basin are lower than anticipated, the supply-demand balance could

⁴⁵ AEMO, Gas statement of opportunities, March 2020. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

⁴⁶ ACCC, Gas Inquiry interim report, September 2017; ACCC, Gas Inquiry interim report, December 2017; ACCC, Gas Inquiry interim report, July 2018; ACCC, Gas inquiry interim report, December 2018; ACCC, Gas Inquiry interim report, July 2019; ACCC, Gas inquiry interim report, January 2020.

tighten, and additional quantities of gas may be required to flow south. As noted in section 4.5, the South West Queensland Pipeline is highly contractually congested, which may create additional uncertainty in the event of a tighter supply-demand balance in the south.

Excluding expected production from the Cooper Basin, the percentage of production from 2P reserves expected to come from undeveloped 2P reserves is highest in the southern states, at 21 per cent. This means that the southern states (excluding the Cooper Basin) are the east coast region most reliant on production from undeveloped 2P reserves.

Compared to the forecast for 2020, supply from the Cooper Basin is expected to be 10 PJ higher in 2021, at around 70 PJ in total.⁴⁷ It is important to note that a portion of the Cooper Basin gas that has been included in the supply forecast is based on producers' expectations of where gas produced in the Cooper Basin is likely to be delivered in 2021, taking into account swap agreements. As previously reported, the bulk of Cooper Basin production is contractually committed to the LNG projects in Queensland.

While the Cooper Basin is expected to contribute to southern states' supply in 2021, due to swap agreements, this may not be the case for future years.

Another portion of Cooper Basin gas that is included in the supply forecast relates to gas acquired by a retailer, which contributes to the retailer's overall portfolio. Where the retailer will deliver this gas will ultimately depend on the retailer's portfolio requirements at the time. As the retailer could deliver some of this gas into Queensland, total gas supply in the southern states may be lower than is shown in the chart.

On the demand side, GPG continues to be a critical factor influencing the supply and demand balance in the southern states. If GPG demand is greater than expected, this could shift the supply-demand balance and result in a tighter outlook. As shown in table 1.1, between 2017 and 2019, annual GPG demand in the east coast has been between 46 PJ lower and 68 PJ higher than forecast.

As noted in section 1.2, GPG demand over the first five months of 2020 was 36 per cent lower than over the same period in 2019. This was due to a combination of factors, including extended heatwaves and prolonged coal-fired power station outages resulting in higher demand in 2019, and the effects of COVID-19 leading to lower demand in 2020. While it is likely that the effects of the COVID-19 pandemic will persist into 2021, its effect on GPG demand is as yet unknown.

1.6. Queensland is likely to have sufficient gas to meet its needs in 2021

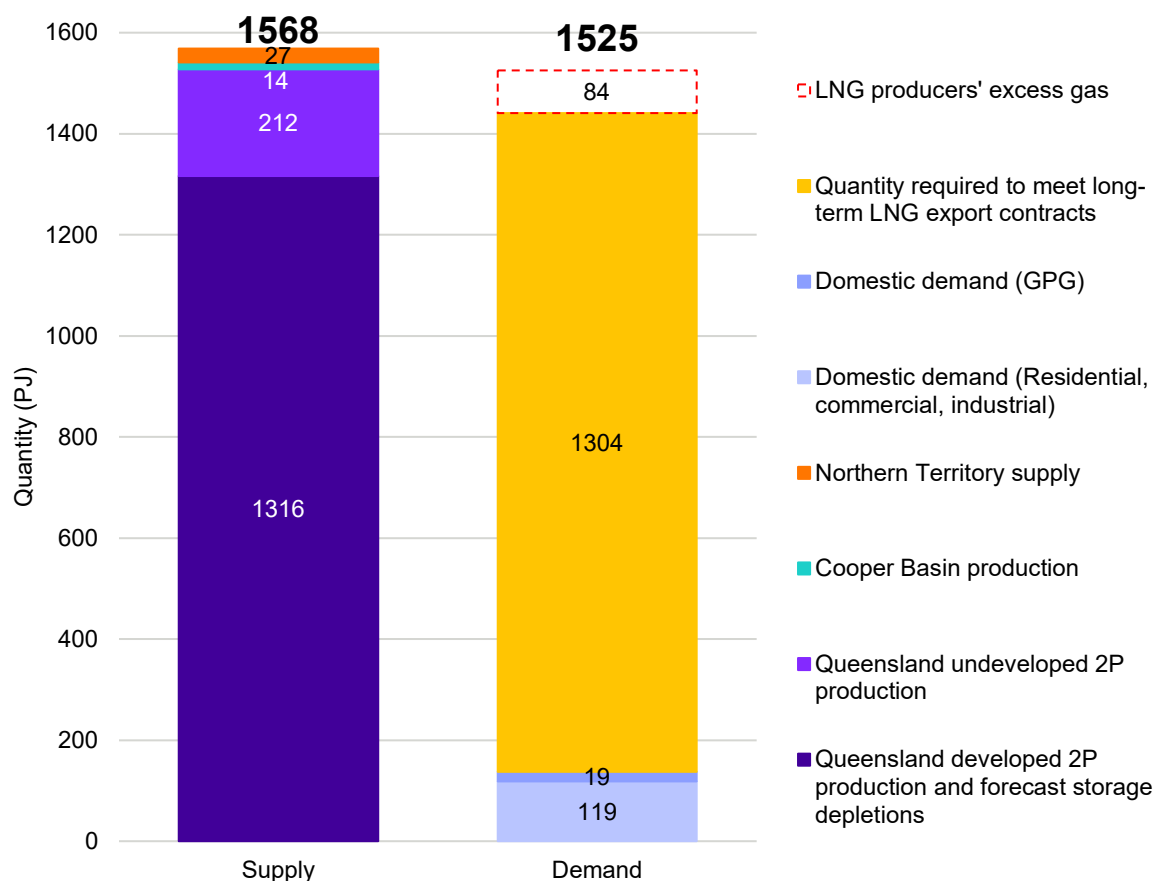
Chart 1.5 presents the supply-demand outlook for Queensland in 2021.

Forecast supply is comprised of Queensland's total expected production from developed and undeveloped 2P reserves, forecast storage depletions, expected supply from the Northern Territory, and a portion of gas from the Cooper Basin (based on producers' delivery expectations and taking into account gas swaps).

Forecast demand is based on AEMO's Central domestic demand forecast for Queensland from its March 2020 GSOO, while forecast long-term LNG contractual demand is based on data obtained directly from producers by the ACCC.

⁴⁷ This figure includes expected storage withdrawals.

Chart 1.5: Forecast supply-demand balance in Queensland for 2021



Source: ACCC analysis of data obtained from gas producers as at May 2020 and of the domestic demand forecast (Central scenario) from AEMO's March 2020 GSOO.⁴⁸

Note: Totals may not add up due to rounding.

Compared to the forecast for Queensland in 2020, Queensland's supply-demand balance is expected to be less tight in 2021. This is because while total expected supply is around 17 PJ lower, expected demand (including the LNG producers' excess gas) is 65 PJ lower.

Supply is expected to be 17 PJ lower in total due to expected Cooper Basin flows being 13PJ lower and expected production from developed 2P reserves (including storage withdrawals) being 26 PJ lower, while expected production from undeveloped 2P reserves is 16 PJ higher and expected flows from the Northern Territory are somewhat higher.

As noted in section 1.2.2, Queensland is less reliant proportionately on production from undeveloped 2P reserves than the Cooper Basin and the southern states. However, given the relatively large quantities of gas produced, Queensland is still expected to contribute around 70 per cent of expected production from undeveloped 2P reserves in the east coast.

1.7. Recent market developments

While the demand and supply sides of the market have been subject to a number of shocks over the last six months, there have also been some positive developments that could result in more gas being supplied to the domestic market over the medium to long term. Some of the more notable developments include the NSW and Commonwealth governments' Energy

⁴⁸ AEMO, Gas statement of opportunities, March 2020. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Package memorandum of understanding (MOU), the Victorian Government's decision to lift its moratoria on onshore conventional natural gas exploration and the Queensland Government's release of more acreage. Further detail on these developments and other recent events that could increase supply is provided below.

However, while these developments should see more gas supplied into the east coast, due to the long lead times between potential gas resources being identified and their development, the range of solutions to address potential gas shortfalls will substantially narrow the closer we get to 2024 (when a potential shortfall in the southern states is first expected to arise).⁴⁹

LNG terminals may appear to be a faster option to bring gas into the east coast market, however there remain material regulatory approvals still to be obtained and the case for each specific business model will need to be established in order to reach FID.

1.7.1. NSW commits to additional 70 PJ of gas supply per year in MOU with Commonwealth

On 31 January 2020, the NSW and Commonwealth governments entered into the NSW Energy Package MOU.⁵⁰ Among other things, the MOU provides for the two governments to work together to develop options to increase gas supply for NSW, improvements to infrastructure and energy efficiency projects.

Under the terms of the MOU, the NSW Government has agreed to set a target to inject an additional 70 PJ per annum of gas into the NSW market and identified the Port Kembla and Port of Newcastle LNG import terminals, and the Narrabri gas project, as priority projects. In doing so, the NSW Government has agreed to work on fast tracking and streamlining regulatory assessments for the Port Kembla import terminal and, if approved, the Newcastle import terminal and Narrabri gas project.

Following the entry into this MOU, the Port Kembla LNG import terminal has received regulatory approval to increase its capacity and the number of LNG cargoes able to be received.⁵¹ Jemena has also announced it has submitted plans to the New South Wales Government to connect an LNG import terminal at Port Kembla to the Eastern Gas Pipeline (EGP).⁵²

The NSW Planning Minister has also referred the Narrabri gas project to the Independent Planning Commission (IPC).^{53,54} The Department of Planning, Industry and Environment's assessment report, released in early June, found that the project 'is in the public interest and

⁴⁹ ACCC, *Gas Inquiry 2017–2025 Interim Report*, January 2020, p. 28; AEMO, *Gas Statement of Opportunities*, March 2020, p. 3.

⁵⁰ Commonwealth of Australia & State of NSW, 'Memorandum of understanding—NSW energy package', 31 January 2020, <https://energy.nsw.gov.au/media/2001/download>.

⁵¹ NSW Department of Planning, Industry and Environment, 'Port Kembla gas terminal modification approved' (Media release), 20 April 2020, <https://www.planning.nsw.gov.au/news/2020/port-kembla-gas-terminal-modification-approved>; Australian Industrial Energy (AIE), 'Project modification approval clears way for final gas supply negotiations and agreements' (Media release), 20 April 2020, https://ausindenergy.com/file/2020/04/AIE_20042020.pdf.

⁵² Jemena, 'Jemena Takes Significant Step Towards Easing East Coast Gas Shortages', Media Release, 11 June 2020.

⁵³ Santos, Narrabri Gas Project referred Independent Planning Commission for public hearings and determination, 12 March 2020 <https://www.santos.com/wp-content/uploads/2020/03/200312-Narrabri-Gas-Project-referred-to-Independent-Planning-Commission-for-public-hearings-and-determination.pdf>

⁵⁴ Minister for Planning and Public Spaces, Request to the Independent Planning Commission Narrabri Gas Project, 3 March 2020, https://www.ipcn.nsw.gov.au/resources/pac/media/files/pac/projects/2020/03/narrabri-gas-project/request-from-minister-for-planning-and-public-spaces/request-for-public-hearing_narrabri.pdf.

is approvable subject to strict conditions'.⁵⁵ The IPC's determination on the development application is expected to be made in September 2020.⁵⁶

1.7.2. Victoria to lift onshore conventional natural gas moratoria and to require new supplies to be reserved for Victorian users

On 17 March 2020, the Victorian Government announced that it would lift its moratoria on onshore conventional natural gas exploration and development from 1 July 2021, but would implement a permanent ban on fracking and CSG exploration in the Victorian Constitution.⁵⁷ The Victorian Government also announced that it would introduce measures to reserve gas for the domestic market.⁵⁸

The reservation is reflected in the *Petroleum Legislation Amendment Act 2020* (Victoria), which was passed on 16 June 2020. In short, the Amendment Act imposes a condition on petroleum production licences granted under the *Offshore Petroleum and Greenhouse Gas Storage Act 2010* (Victoria) on or after 1 May 2018 that the licensee:

...must not supply petroleum recovered under the license to an LNG exporter unless—

- (a) the licensee has first taken all reasonable steps to supply that petroleum to a domestic consumer on reasonable terms; and*
- (b) there is no domestic consumer willing to buy the petroleum on reasonable terms.*⁵⁹

The lifting of the moratoria on onshore conventional natural gas exploration and development follows a three year review by Victoria's Lead Scientist, who found that onshore conventional natural gas could be developed without harming the environment. The review found that there could be between 128 PJ and 830 PJ of onshore conventional natural gas in both the Otway and Gippsland basins, with the majority being located in the Otway Basin.⁶⁰ While drilling can commence from 1 July 2021, the Victorian Government noted production was unlikely to occur until 2022–23.⁶¹

The Victorian Government also announced that it would soon be releasing new offshore acreage in state waters next to existing sites.⁶² This follows an earlier announcement by the Commonwealth Government that it would release more acreage in Commonwealth waters in both the Otway and Gippsland basins.⁶³ Bidding for the Commonwealth acreage closed in March 2020, with bids received for three of the seven release areas, all of which are located in eastern Gippsland.⁶⁴ The outcome of this release was expected to be announced in the second quarter of 2020.⁶⁵

⁵⁵ NSW Department of Planning, Industry and Environment, Narrabri Gas Project – State Significant Development, June 2020, p. iv.

⁵⁶ Santos, 2020 Annual General Meeting, 3 April 2020, p. 5.

⁵⁷ Hon. Daniel Andrews, Backing the Science, Protecting Farmers and Boosting Jobs, 17 March 2020.

⁵⁸ The Age, Victorian Premier addresses media (video), 17 March 2020.

⁵⁹ *Petroleum Legislation Amendment Act 2020* (Victoria), s. 152A.

⁶⁰ Department of Jobs, Precincts and Regions, Victorian Gas Program – Progress Report No. 4, March 2020, p. 6.

⁶¹ The Age, Victorian Premier addresses media (video), 17 March 2020.

⁶² Hon. Daniel Andrews, Backing the Science, Protecting Farmers and Boosting Jobs, 17 March 2020.

⁶³ Commonwealth Department of Industry, Science, Energy and Resources, 2019 Offshore Petroleum Exploration Acreage Release, July 2019 <https://www.industry.gov.au/data-and-publications/2019-offshore-petroleum-exploration-acreage-release>

⁶⁴ Department of Industry, Science, Energy and Resources, 'Bidding closes for 2019 acreage release', Australian petroleum news, 18 March 2020, <https://mailchi.mp/industry/australian-petroleum-news-18-march-2020>.

⁶⁵ Ibid.

1.7.3. Queensland continues to encourage exploration and the supply of gas into the domestic market through the release of more acreage

In late May, the Queensland Government announced that Santos and Denison Gas had won the latest tender for gas exploration acreage released to promote domestic supply. The 2000 km² of acreage, awarded to Santos through four new gas exploration permits, is located between Chinchilla and Roma in the Surat and Bowen basins, while the 568 km² of acreage awarded to Denison Gas is located south-east of Emerald in the Bowen Basin.⁶⁶ Of the four exploration permits granted to Santos, two are for domestic only supply and two can be used to supply either the domestic or LNG markets.⁶⁷

Earlier in May, the Queensland Government announced that it would be conducting a tender for a further 12 prospective parcels of acreage (6700 km²) located close to existing projects near Blackwater and Goondiwindi, with 872 km² to be reserved for domestic supply.⁶⁸ The Queensland Government also announced that a relief package was available to eligible explorers to 'help maintain the state's pipeline of resource projects'.⁶⁹ Amongst other things, the relief package provides for a rent waiver for exploration permit and authority holders, and the capping of all other fees and charges.⁷⁰

These announcements follow the March 2020 announcement by the Queensland Government that it had awarded new exploration permits to Pure Energy/Strata X and Santos in the Surat Basin. The exploration permit awarded to Pure Energy/Strata X relates to 153 km² of acreage located west of Miles, while the permit awarded to Santos relates to 101 km² of acreage located near Wallumbilla.⁷¹

1.7.4. A number of new supply sources are expected in the south, but changed conditions may affect the timing of some projects

Over the last six months, two new sources of supply have come online in the south:

- Cooper Energy's Sole gas field in the Gippsland Basin, which is processed at APA's Orbost gas plant (capacity 68 TJ/day).⁷² While supply from this field was expected to commence in 2019, it was delayed until early 2020 and then further delayed by bushfires in east Gippsland and technical issues experienced by the Orbost gas plant. By the end of mid-June 2020, the plant was still in commissioning stages, averaging 34 TJ/day from 20 May 2020.⁷³
- Beach Energy's Haselgrove-3 gas field in the Otway Basin, which is processed through Beach's recently upgraded Katnook gas plant (capacity 10 TJ/day).⁷⁴

⁶⁶ Queensland Department of Natural Resources, Mines and Energy, Santos and Denison to pump more Queensland Gas, 25 May 2020, <https://www.dnrme.qld.gov.au/home/news-publications/news/2020/may/santos-and-denison-to-pump-more-queensland-gas>.

⁶⁷ Santos, Media Release—Santos wins new gas exploration acreage in Queensland, 25 May 2020.

⁶⁸ Queensland Department of Natural Resources, New land opens to support more gas flow and jobs, 14 May 2020, <https://www.dnrme.qld.gov.au/home/news-publications/news/2020/may/new-land-opens-to-support-more-gas-flow-and-jobs>.

⁶⁹ Queensland Department of Natural Resources, Multi-million dollar relief package for explorers, 6 May 2020, <https://www.dnrme.qld.gov.au/home/news-publications/news/2020/may/multi-million-dollar-relief-package-for-explorers>

⁷⁰ Ibid.

⁷¹ Queensland Department of Natural Resources, Mines and Energy, More Queensland gas in the pipeline, 24 March 2020, <https://www.dnrme.qld.gov.au/home/news-publications/news/2020/march/more-queensland-gas-in-the-pipeline>

⁷² Cooper Energy, Sole Gas Project update, 19 June 2020, <https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Sole-orbost-update-June-19-.pdf>.

⁷³ Ibid

⁷⁴ Beach Energy, FY20 Third Quarter Activities Report, 22 April 2020, https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.aspx/2A1221222/BPT_Quarterly_report_for_the_period_ended_31_March_2020.pdf.

Beach Energy also expects supply from the Black Watch-1 to commence this year, with gas from this field to be processed by the Otway Gas Plant.

For 2021, Esso announced in early March that the Gippsland Basin Joint Venture had commenced drilling in the West Barracouta field and that gas from this field was expected to be supplied into the domestic market in early 2021.⁷⁵ This followed Esso's parent company, ExxonMobil, announcing that it would not be proceeding with its proposed LNG import terminal.⁷⁶

Of the remaining proposed LNG import terminals, AIE (Port Kembla), Epik (Newcastle) and AGL (Crib Point) are yet to make a final investment decision on whether to proceed with respective projects, although AIE has noted that it intends to do so in September 2020.^{77,78} According to AIE, if a decision is made to proceed with the development of the Port Kembla import terminal in NSW, then it could be operational by the first quarter of 2022 and have a capacity of 100 PJ per annum.⁷⁹

AGL also expects its proposed Crib Point terminal in Victoria to be operational in the second half of 2022 and to have a capacity of 550–750 TJ/day if it obtains all the necessary environmental and regulatory approvals. The first step to obtaining the required environmental approvals was taken in May, when AGL and APA submitted a joint environment effects statement to the Victorian Department of Environment, Land, Water and Planning for an adequacy assessment.⁸⁰

While there have been some positive developments in the south over the last six months, some upstream activities are expected to be affected by low oil prices and the contraction in economic activity brought about by the COVID-19 pandemic (as noted in section 1.2). Cooper Energy, for example, stated in April 2020 that the 'timing and sequencing' of its Otway Basin growth projects may change and there may be some 'slippage' in dates for projects, although this is not anticipated to have a material impact on 2020 or 2021 production.⁸¹

Beach Energy also announced in late March that while it was 'well placed to continue growth investment', it was targeting a 30 per cent deferral of capital expenditure for 2021 in response to changed conditions.⁸² Beach noted this was expected to be achieved through the 'deferral and re-phasing of drilling and development activity'⁸³ and would affect all basins in which it operates.⁸⁴ A month later, Beach announced that its Otway Basin offshore drilling campaign, which was targeting production by financial year 2023,⁸⁵ would be delayed until 2021 as a result of a dispute with rig provider Diamond Offshore.⁸⁶

⁷⁵ Esso, Esso Australia drilling West Barracouta domestic gas wells, 6 March 2020. <https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2020/Esso-drilling-for-West-Barracouta-gas>, AFR, Exxon 'pauses' Bass Strait drilling, 15 April 2020.

⁷⁶ SMH, ExxonMobil shelve Victorian gas import terminal plan, 2 December 2019.

⁷⁷ AIE website: <https://ausindenergy.com/our-project/>, accessed 1 June 2020.

⁷⁸ The Australian, NSW, Victoria at risk of LNG shortage, 8 June 2020.

⁷⁹ Ibid.

⁸⁰ AGL, Gas import jetty and pipeline project website: <https://gasimportprojectvictoria.com.au/environment-effects-statement-submitted-adequacy-assessment>.

⁸¹ Cooper Energy, Quarterly report for 3 months to 31 March 2020, 21 April 2020.

⁸² Beach Energy, Business update, 27 March 2020.

⁸³ Ibid.

⁸⁴ Beach Energy, Macquarie Australia Conference, 7 May 2020, slide 11. https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1224421/BPT_Macquarie_Australia_Conference_Presentation.pdf.

⁸⁵ Beach Energy, Victorian Otway Basin Site Visit, 24-25 September 2019. <https://www.asx.com.au/asxpdf/20190924/pdf/448tfv5hcg18mm.pdf>.

⁸⁶ Beach Energy, FY20 Third Quarter Activities Report, 22 April 2020, https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1221222/BPT_Quarterly_report_for_the_period_ended_31_March_2020.pdf.

1.7.5. Changed market conditions may also affect the timing of new projects in the north

In a similar manner to the south, a number of new sources of supply have come online in the Cooper, Surat and Bowen basins over the last six months, including:

- Senex's Atlas Project in the Surat Basin, with supply from this project commencing in December 2019 and expected to continue to grow through to the end of financial year 2021 as new wells are brought online⁸⁷
- Senex's Gemba field in the Cooper Basin, with supply from this project also commencing in December 2019⁸⁸
- Denison Gas's North Denison Project in the Bowen Basin, with supply from this project commencing in March and expected to ramp up over the remainder of 2020 as additional fields are brought online.⁸⁹

A number of new sources of supply in the north are also expected to come online in 2021. The Queensland Government, for example, announced on 11 March 2020 that it had granted a production licence for the Murrungama field. This field, which was awarded to APLNG and Armour Energy in mid-2019 and has been reserved solely for the use of local manufacturers, is expected to supply up to 103 PJ of gas over a 30 year period, with supply currently expected to commence in 2021.⁹⁰ On 18 June 2020 Armour Energy announced it would be selling its 10 per cent interest in the field to APLNG.⁹¹

Arrow Energy also announced on 17 April 2020 that a final decision had been made to proceed with the development of the first phase of the long-awaited Surat Gas Project.⁹² Supply from the Surat Gas Project, which has been underpinned by a 27-year Gas Sales Agreement with QGC⁹³, is expected to commence in 2021 and to ramp up over time.⁹⁴ Over the 27-year life of the project, Arrow expects to produce around 5000 PJ of gas.⁹⁵

While the decision to proceed with these developments is positive, a number of producers operating in the north have announced cuts in capital expenditure and delays to their proposed exploration activities in response to low oil prices and the impact of COVID-19 on economic activity.

Central Petroleum, for example, announced in late March that it would delay its 2020 Amadeus Basin exploration program and 'temporarily pause' work on the Range Gas Project that it is developing with Incitec Pivot.⁹⁶ Central later announced that it would defer

⁸⁷ Senex, Quarterly report for the period ending 31 December 2019, 23 January 2020, <https://www.senexenergy.com.au/wp-content/uploads/2020/01/2021434.pdf>.

⁸⁸ Senex, First gas sales from Gemba gas field, 5 December 2019. <https://www.senexenergy.com.au/wp-content/uploads/2019/12/2008522.pdf>.

⁸⁹ Denison Gas, Re-starts North Denison gas sales after 9yr shut-down, 26 March 2020, <https://denisongas.com.au/media-release-re-starts-north-denison-gas-sales-after-9yr-shut-down/>.

⁹⁰ Queensland Department of Natural Resources, Qld gas to flow for Aussie manufacturers jobs, 11 March 2020. <https://www.dnrme.qld.gov.au/home/news-publications/news/2020/march/qld-gas-to-flow-for-aussie-manufacturers-jobs>.

⁹¹ On 18 June 2020 Armour Energy announced it would be selling its 10 per cent interest in the field to APLNG. See: Armour Energy, Armour Energy and Australia Pacific LNG execute a sale and purchase agreement for PL1084 (Murrungama), 18 June 2020, <https://wcsecure.weblink.com.au/pdf/AJQ/02245696.pdf>.

⁹² Arrow Energy, Start planned for Arrow's Surat Gas Project, 17 April 2020. <https://www.arrowenergy.com.au/media/media-releases/current-releases/arrow-sanctions-start-to-sgp>.

⁹³ Shell, Shell invests in Arrow Energy's Surat Gas Project, 17 April 2020, <https://www.shell.com/media/news-and-media-releases/2020/shell-invests-in-arrow-energy-surat-gas-project.html>.

⁹⁴ Queensland Department of Natural Resources, \$10 billion flows for Arrow Gas Project, 17 April 2020, [https://www.dnrme.qld.gov.au/home/news-publications/news/2020/april/\\$10-billion-flows-for-arrow-gas-project](https://www.dnrme.qld.gov.au/home/news-publications/news/2020/april/$10-billion-flows-for-arrow-gas-project).

⁹⁵ Arrow Energy, Start planned for Arrow's Surat Gas Project, 17 April 2020. <https://www.arrowenergy.com.au/media/media-releases/current-releases/arrow-sanctions-start-to-sgp>.

⁹⁶ Central Petroleum, Operational Update, 27 March 2020. <https://wcsecure.weblink.com.au/pdf/CTP/02219165.pdf>.

investment in new production wells, because additional production capacity was not required to meet its firm gas supply contracts.⁹⁷

Similarly, Origin Energy announced in March that it had decided to ‘temporarily pause’ activities in the Beetaloo Basin in response to the ‘unprecedented circumstances brought about by COVID-19’.⁹⁸ Origin also announced in April that it would be pursuing a range of other cost reduction initiatives in 2020–21, including a 25–30 per cent reduction in capital expenditure and a \$300–\$400 million reduction in APLNG upstream capital expenditure.⁹⁹

In contrast, Senex Energy and Galilee Energy have stated that their proposed developments will not be affected by the changed market conditions.¹⁰⁰

1.8. Comparative analysis of forecast and realised production and demand in the East Coast Gas Market

Previous ACCC gas inquiry reports have included short- and long-term forecasts of gas production in the East Coast Gas Market. For this reporting, the ACCC has used its compulsory information gathering powers to obtain detailed production forecast information from east coast gas producers.

In mid-year reports, the ACCC has compared short-term production forecasts for the following supply year to AEMO’s forecasts of domestic demand, in order to determine the likelihood of the East Coast Gas Market experiencing a gas supply shortfall. This has been prepared in anticipation of a potential request for the ACCC’s advice to the Commonwealth Government under the Australian Domestic Gas Security Mechanism (ADGSM).

This section provides, for the first time in this inquiry, a comparative analysis of forecasts of east coast gas production and actual gas production between 2017 and 2019. We also compare these with contemporaneous AEMO forecasts of domestic demand, and AEMO’s reporting of actual demand.

All forecasts in this analysis are based on the forecasts used in the ACCC’s mid-year reports—that is, they are based on producer forecasts provided in the first half of the year for the following supply year. An exception to this is 2017 (the first year of this inquiry) when forecasts were obtained from suppliers during the 2017 supply year.

We have used these mid-year forecasts¹⁰¹ for this comparative analysis because it is these forecasts that were provided to both the ACCC and AEMO at similar points in time for the purpose of advising the Commonwealth Government under the ADGSM, and as such it is these forecasts that were relied upon in forming a view around the likelihood of a gas supply shortfall for each year.

The ACCC will include updated analysis of forecast and actual production in each of its mid-year inquiry reports for the remainder of the inquiry.

⁹⁷ Central Petroleum, March 2020 Quarterly Update, 14 May 2020. <https://wcsecure.weblink.com.au/pdf/CTP/02235281.pdf>.

⁹⁸ Origin Energy, Beetaloo Exploration Program update, 26 March 2020. https://www.originenergy.com.au/about/investors-media/media-centre/beetaloo_exploration_program_update1.html.

⁹⁹ Origin Energy, Operational and financial update, 6 April 2020. https://www.originenergy.com.au/about/investors-media/media-centre/operational_and_financial_update.html.

¹⁰⁰ Senex Energy, Senex COVID-19 response and business update, 27 March 2020 <https://www.senexenergy.com.au/wp-content/uploads/2020/03/2047137.pdf> and Galilee Energy Limited, Letter to Shareholders, 19 March 2020 <http://galilee-energy.com.au/wp/wp-content/uploads/2020/03/2216060.pdf>.

¹⁰¹ As opposed to forecasts obtained from suppliers later in the year for the purpose of the ACCC’s end-of-year reporting.

1.8.1. Overall supply and demand

Table 1.1 below shows forecast and actual supply and demand across the East Coast Gas Market between 2017 and 2019. It also shows a breakdown of these totals into geographic regions for production and market segments for demand.

We note that this table does not include forecast or actual LNG demand above long-term LNG contracts, such as LNG spot sales. This is because, since the first report in this inquiry (September 2017) we have not included additional or spot LNG sales as part of LNG demand forecasts on the basis that they are typically highly uncertain and are part of LNG producers' expected excess gas which could either be sold as additional LNG or used to supply the domestic market. As a result, the forecasts shown in this table for 2018 differ from the September 2017 report.

Table 1.1 shows that, overall, the market has been adequately supplied in each year over the period. While the extent to which gas supply forecasts have exceeded domestic and LNG contract demand has fluctuated significantly (between 8 PJ and 151 PJ) actual differences between supply and these measures of demand have been within a smaller range (51 and 63 PJ).

These differences are mostly accounted for by LNG spot or additional sales (discussed in section 1.8.3 below), and other sources of gas usage not measured in table 1.1 such as domestic storage, and other factors such as losses, gas used for compression and unaccounted for gas.

The table also shows that both supply and demand were less than forecast for 2017 and 2018. In 2019 this was reversed, with demand significantly higher than forecast (mainly due to higher than forecast GPG demand).

This additional demand was still met, however, with actual east coast production exceeding forecasts in 2019 by 18 PJ. While gas production in the southern states was significantly lower than forecast in 2019 by 21 PJ, production in Queensland and the Cooper Basin appears to have picked up and exceeded forecasts in 2019. This more than offset the reduction in southern production. The unexpected increase in demand in 2019 (largely arising from GPG in the southern states) appears to have been met with gas produced in Queensland and the Cooper Basin, with net pipeline flows at Moomba showing a significant increase in southbound gas flows in 2019.¹⁰²

Residential and C&I demand have been relatively close to AEMO forecasts (demand in these market segments has been historically stable), while LNG demand was less than forecast in 2017 and 2018 and more than forecast in 2019. LNG demand is discussed further in section 1.8.3 below.

¹⁰² AER, *Wholesale Markets Quarterly Q1 2020*, May 2020, p. 52.

Table 1.1: Overall supply and demand

Component Unit	2017				2018				2019				
	Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual	Difference		
	PJ	PJ	PJ	%	PJ	PJ	PJ	%	PJ	PJ	PJ	%	
Supply	Queensland	1399.6	1325.9	-73.7	-5.3	1450.0	1373.6	-76.4	-5.3	1456.0	1474.9	18.9	1.3
	Cooper Basin	81.7	84.1	2.5	3.0	85.0	85.9	0.9	1.1	79.0	86.5	7.5	9.5
	Southern States	444.8	441.7	-3.1	-0.7	348.0	351.2	3.2	0.9	370.0	348.6	-21.4	-5.8
	Storage withdrawals	NA	20.8	NA	NA	17.6	17.6	0.0	-0.2	15.0	6.8	-8.2	-54.6
	NT supply	NA	NA	NA	NA	NA	NA	NA	NA	28.0	33.8	5.8	20.6
Demand	Residential & commercial	190.5	193.3	2.8	1.5	466.0	189.7	-20.0	-4.3	189.5	190.5	1.0	0.5
	Industrial	257.4	255.1	-2.3	-0.9	256.4	256.4			258.4	255.2	-3.2	-1.2
	GPG	150.1	183.8	33.6	22.4	176.0	129.9	-46.1	-26.2	87.1	155.5	68.4	78.6
	LNG demand (contract)	1219.1	1161.4	-57.7	-4.7	1251.0	1201.8	-49.2	-3.9	1262.3	1286.4	24.1	1.9
Supply total	1926.0	1851.7	-74.3	-3.9	1900.6	1828.3	-72.3	-3.8	1948.0	1950.7	2.6	0.1	
Demand total	1817.1	1793.5	-23.6	-1.3	1893.0	1777.8	-115.3	-6.1	1797.2	1887.6	90.4	5.0	
Difference	109.0	58.3	-50.7	-46.5	7.6	50.5	42.9	565.0	150.8	63.1	-87.7	-58.2	

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

Note: This table does not include forecast or actual LNG demand above long-term LNG contracts, such as LNG spot sales. This is because, since the first report in this inquiry (September 2017) we have not included additional or spot LNG sales as part of LNG demand forecasts on the basis that this is part of LNG producers' expected excess gas which could either be sold as additional LNG or used to supply the domestic market. As a result, the forecasts shown in this table for 2018 differ from the September 2017 report.

The actual supply total for 2017 does not include storage withdrawals as forecasts of these for 2017 are not available.

Totals may not add up due to rounding.

1.8.2. Forecast and actual production

Table 1.2 below shows forecast and actual production across the east coast gas market over the period. This table also separately shows total production across the three LNG producers in Queensland.

Table 1.2 shows that production levels in 2017 and 2018 were significantly below forecast. This appears to have been driven by the LNG producers, who produced between 68 and 70 PJ less than forecast in these years (a difference of around 5 per cent of expected production each year). In contrast, producers in the southern states produced within around 3 PJ of forecasts in these years (difference of less than 1 per cent).

LNG producers have therefore been least accurate in their forecasting for these years. This may be due in part to the uncertainties associated with CSG development and unpredictability of well performance relative to conventional sources of supply. However, we note that these differences between forecast and actual production are at an aggregate level. At the individual LNG producer level, there is a wide range of forecasting accuracy—one LNG producer has consistently produced within 1–2 per cent of forecast, while others have reported production levels up to 17 per cent different from forecasts.

That actual production in 2017 was so far below forecast is particularly noteworthy, given that these forecasts were made during the supply year in question. Part of 2017 had already passed when the forecasts were made, and the forecast horizon was much shorter (less than one year). In contrast, production forecasts for 2018 and 2019 were made in the first half of the year prior to the supply year.

These 2017 and 2018 results appear to have reversed in 2019, however, with producers in the southern states producing 21 PJ less than forecast (6 per cent) and LNG producers producing about 40 PJ more than forecast (3 per cent).

These appear to be partly due to two key trends over 2017–2019:

- Queensland production has increased from 1274 PJ to 1406 PJ, while
- production in the southern states has decreased from 442 PJ to 349 PJ.

For the southern states this represents a greater than 21 per cent reduction in production since 2017. This appears to be mostly due to declining production in traditional sources of supply in the Gippsland Basin which, as the ACCC has previously discussed in this inquiry, are reaching the end of their economic life. EnergyQuest has recently noted that, while GBJV annual production increased in 2019, annual production was still almost 20 per cent below 2017 levels.¹⁰³

These two trends (increasing production in Queensland and declining production in the southern states) are currently expected to continue in the short to medium term. As discussed in the ACCC's January 2020 report, production from developed and undeveloped 2P reserves in Queensland is expected to grow until 2023 and gradually decline thereafter. In contrast, production from developed and undeveloped 2P reserves in the southern states is expected to decline from 2021, falling below southern demand by 2024.¹⁰⁴

However, in contrast to the southern states, producers in the Cooper Basin have outperformed forecasts over the three year period, with actual production rising steadily to a high of 87 PJ in 2019. EnergyQuest has noted that production from the Cooper Basin JV increased over 2019 to the highest level of production in almost five years (since

¹⁰³ EnergyQuest, *EnergyQuarterly*, March 2020, p. 99.

¹⁰⁴ ACCC, *Gas Inquiry 2017–2025 Inquiry Report*, January 2020, pp. 27–28.

Q2 2015).¹⁰⁵ Santos has recently noted that it has achieved its highest level of Cooper Basin gas production in nine years.¹⁰⁶

Overall, there has been a general improvement at an aggregate level across producers over the period. While actual production was significantly less than forecast in 2017 and 2018, it was above forecast in 2019. This appears driven by the LNG producers, which despite inaccurate forecasts in 2017 and 2018, have produced steadily increasing quantities over time.

¹⁰⁵ EnergyQuest, *EnergyQuarterly*, March 2020, p. 100.

¹⁰⁶ Santos, Macquarie Australia Conference presentation, p. 6.

Table 1.2: Forecast and actual production

	2017			2018			2019		
	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference
LNG producers	1343.5	1273.7	-69.8	1380.0	1312.4	-67.6	1366.0	1406.3	40.3
Non-LNG producers	582.6	578.5	-4.0	503.0	498.3	-4.7	526.0	503.8	-22.3
Queensland	1399.6	1325.9	-73.7	1450.0	1373.6	-76.4	1456.0	1474.9	18.9
Cooper Basin	81.7	84.1	2.5	85.0	85.9	0.9	79.0	86.5	7.5
Southern States (excl. Cooper)	444.8	441.7	-3.1	348.0	351.2	3.2	370.0	348.6	-21.4
East coast total	1926.0	1851.7	-74.3	1883.0	1810.7	-72.3	1892.0	1910.1	18.1

Source: ACCC analysis of information provided by suppliers.

Table 1.3: LNG producers' gas usage, domestic purchases and domestic sales

	2017			2018			2019		
	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference
LNG feed gas (contract)	1219.1	1161.4	-57.7	1251.0	1201.8	-49.2	1262.3	1286.4	24.1
LNG feed gas (additional)	70.5	84.5	14.1	63.0	46.4	-16.6	96.5	51.5	-45.0
Domestic purchases	112.2	236.8	124.6	189.0	242.2	53.2	199.0	223.9	24.9
Domestic sales	281.3	318.2	36.9	229.0	332.5	103.5	205.0	293.6	88.6
Net contribution	169.1	81.4	-87.7	40.0	90.3	50.3	6.0	69.7	63.7

Source: ACCC analysis of information provided by suppliers.

Note: Differences between forecast and actual feed gas can arise for a range of reasons, including the approach taken to fuel usage and maintenance, and unexpected changes in economic and operational conditions during the relevant year.

1.8.3. LNG producers' gas usage, domestic purchases and supply

Table 1.3 shows aggregated forecast and actual data on the LNG producers' feed gas requirements¹⁰⁷, as well as their gas purchases from and sales to the domestic market.

The feed gas data in table 1.3 is separated into feed gas required for contracts and additional LNG sales. The former reflects the quantity of gas used by LNG producers to meet their long-term LNG contracts with JV parties and other international buyers; the latter reflects the gas used for any additional or LNG spot market sales.

Forecasts for LNG additional sales should be treated with caution, as the extent to which LNG producers actually sell LNG into spot markets is highly uncertain and depends on a range of factors including the level and timing of production within the year. In addition, the Heads of Agreement between LNG producers and the Commonwealth Government was in effect for the 2018 and 2019 supply years. This means that quantities of gas that LNG producers may have expected to export above long-term contract levels would, in the first instance, have to be offered to the domestic market.

The domestic purchase data in table 1.3 shows the quantity of gas the LNG producers have procured from the domestic market under GSAs (the large majority of which is used for LNG production); the domestic sales data shows the gas the LNG producers have sold under GSAs to domestic buyers. Together, this data can be used to estimate the extent to which the LNG producers have, in aggregate, been net contributors to the domestic market. In particular, it can be used to determine the extent to which the LNG producers indicated to the ACCC they *expected* to be net contributors to the market, and the extent to which this was realised.

Domestic purchases and sales

Table 1.3 shows that, while gas quantities purchased from and sold to the domestic market have both fluctuated over the period, LNG producers have tended to underestimate both of these.

For the 2017 supply year, LNG producers appear to have underestimated purchases from the domestic market to a greater extent than sales to the domestic market. However, for the 2018 and 2019 supply years, this reversed, with LNG producers underestimating sales to the domestic market to a greater extent than purchases from the domestic market. Despite these differences, however, LNG producers appear to have actually supplied the domestic market with more gas than they have taken out in all three years. LNG producers contributed 81 PJ, 90 PJ and 70 PJ (in net terms) to the domestic market in 2017, 2018 and 2019 respectively.

In 2019 LNG producers used 24 PJ more for LNG contracts than was forecast and also produced 40 PJ more than forecast which allowed them to sell more into the domestic market than they had forecast (offsetting lower than forecast production in the southern states), as well as selling a number of spot cargoes into international LNG markets.

As noted in section 1.3.1 above, the East Coast Gas Market is expected to become more reliant on production from undeveloped 2P reserves in 2021 than it has been in the past. This applies most significantly to the southern states, and to a lesser extent to Queensland. Given the additional uncertainty this brings to production forecasts, this might lead to an

¹⁰⁷ The term 'feed gas' means the total quantity of gas used in in the production of LNG. That is, it reflects the quantity of gas fed into the LNG facilities. While most of this gas is converted to LNG and exported, some (around 8 per cent) is consumed as fuel to run the plant.

increase in LNG producers' reliance on domestic sources of supply other than their own equity production.

LNG exports

Table 1.3 shows that forecasts for the total quantities of gas used for LNG exports have generally increased between 2017 and 2019.

While actual gas used for LNG contracts has steadily risen over the period (from 1161 PJ to 1286 PJ), gas used for additional LNG sales has fallen significantly (from 85 PJ to 52 PJ). With 14 PJ more gas being exported as additional LNG cargoes than expected in 2017, LNG producers exported less than forecast in both 2018 and 2019, by 17 PJ and 45 PJ respectively. In part, this reduction appears due to LNG producers having redirected gas to the domestic market that would otherwise have been converted to LNG and exported.

As noted in section 1.3.1, LNG producers expect LNG demand to increase in the near term. However this could be affected by the potential for LNG buyers to exercise additional DQT rights under their contracts with LNG producers and the ability of the LNG producers to find alternative buyers for the LNG.

Table 1.3 shows that gas used for LNG contracts in 2017 was significantly lower than forecast (by 58 PJ). However, this coincided with a 70 PJ drop in production below forecasts by LNG producers (as shown in table 1.2). As noted above, in 2017 the extent to which LNG producers purchased more gas from the domestic market than expected was greater than the extent to which LNG producers sold more gas to the domestic market, and it appears that LNG producers addressed this lower than expected production in part by procuring more gas from the domestic market than expected. LNG producers were still, however, net contributors to the domestic market in 2017.

Similarly, in 2018 LNG producers used 49 PJ less for their LNG contracts than forecast, and also produced 68 PJ less than was previously expected. Again, LNG producers appear to have made up for this in part with domestic purchases, however, as noted above, LNG producers were also net contributors to the domestic market in 2018.

In 2019, LNG producers used 24 PJ more for LNG contracts than was forecast and also produced 40 PJ more than forecast. While again underestimating the quantity of gas that would be purchased from the domestic market, LNG producers underestimated the quantity that would be sold to domestic buyers in 2019 by a much greater amount.

1.8.4. Cooper Basin flows and NT supply

The Cooper Basin has historically served demand in the southern states (particularly SA and NSW). However, since the commissioning of the QSN Link, the conversion of the SWQP to a bi-directional pipeline, and the establishment of the LNG facilities in Queensland, significant quantities of gas have flowed from the Cooper Basin to Queensland, mostly for LNG production.

Given that gas from the Cooper Basin can now be used to either supply demand for gas in Queensland or the southern states, the ACCC has generally reported on supply from the Cooper Basin separately when reporting on supply forecasts.

Further, since the commissioning of the NGP in January 2019, the ACCC now reports on forecast gas supply into the East Coast Gas Market from the Northern Territory.

Cooper Basin and the NT are important sources of supply for the east coast market—the extent to which Cooper Basin gas flows south means that it is being used for the domestic market rather than LNG. Further, gas from the NT can either be used to supply users in the

NT or in the east coast (noting that NT gas may displace gas produced in the east coast which could then be exported).

Table 1.4 below shows forecast and actual total gas flows from the Cooper Basin to both Queensland and the southern states in 2019, and actual flows in 2017 and 2018. Table 1.5 shows forecast and actual total gas supplied to the East Coast Gas Market from the NT in 2019. The data available to the ACCC is more limited in these respects than for production and other forecasts discussed above, because the ACCC did not obtain Cooper Basin flow forecasts for 2017 and 2018; and the NGP was not operational until the beginning of 2019.

Table 1.4: Cooper Basin flows

Region	2017	2018	Forecast	2019	Difference
	Actual	Actual		Actual	
Queensland	37.3	8.7	2.0	11.6	9.6
Southern states	23.5	56.2	58.2	55.8	-2.4

Source: ACCC analysis of information provided by suppliers.

Table 1.5: Northern Territory supply

Forecast	2019	Difference
	Actual	
27.9	33.8	5.9

Source: ACCC analysis of information provided by suppliers.

Table 1.4 shows that Cooper Basin gas flows to Queensland dropped significantly between 2017 and 2018 (from 37 PJ to 9 PJ), and then remained largely stable between 2018 and 2019. Conversely, flows to the southern states increased significantly in 2018 (from 23 PJ to 56 PJ) and remained around this level in 2019. This a positive development given the tightness of supply in the southern states over recent years, caused in part by the flow of domestic gas supply to the LNG projects.

However, comparing forecast and actual Cooper Basin flows in 2019, it appears that producers had originally forecast a further drop in Queensland flows and a further increase in flows to the southern states. Data for actual flows shows that this did not occur, with flows to Queensland being almost six times what was forecast, while flows to the southern states were more than 2 PJ less than forecast.

These unexpected flows to Queensland may be partly explained by the additional production in the Cooper Basin, as noted in section 1.8.2 above.

Table 1.5 above shows that actual gas supply from the NT exceeded forecasts by almost 6 PJ (21 per cent). This is encouraging, and with total supply from NT at 34 PJ and potential to grow further (subject to NGP capacity constraints) this shows the importance of NT gas as an additional source of supply for the East Coast Gas Market.

2. Domestic price outlook for 2020 and 2021

2.1. Key points

- LNG and oil prices fell precipitously in late 2019 and early 2020, each decreasing by over 40 per cent between January and May 2020 (in part due to the Covid-19 pandemic).
- Over the same period, to February 2020, there has been a slight softening in prices offered in the domestic market by producers and retailers.
 - Over the second half of 2019, prices offered by gas producers for supply in 2020 and 2021 have followed a downward trend, with most offers from producers falling within the range of \$8–10/GJ, reflecting declines in both fixed price offers and those offers with pricing linked to oil prices.
 - Over the same period, prices offered by retailers also fell, with most offers from retailers falling within the \$9–11/GJ range.
 - The ACCC has seen anecdotal evidence that prices have fallen further since February 2020, with prices being offered in Queensland falling below \$7/GJ. However, these prices are still above LNG netback prices.
- While prices offered have softened somewhat, average prices offered in Queensland, for supply in both 2020 and 2021, remain above expected LNG netback prices.
 - Average prices offered for 2021 supply in February 2020 were more than \$2/GJ higher than expected LNG netback prices in 2021.
 - This is extremely concerning, and raises serious questions about the level of competition among producers in the East Coast Gas Market.
 - To better understand this, the ACCC recently issued compulsory information notices to key suppliers seeking information on their pricing strategies. The ACCC will report relevant findings in subsequent reports.
- Prices agreed to under Gas Supply Agreements (GSAs) in some regions moderated slightly over the latter months of 2019 and in early 2020.
 - In January 2020, the ACCC noted that average prices in GSAs entered into by C&I gas users, calculated on a six-monthly basis, had risen above \$10/GJ for the first time. These averages have since fallen below the \$10/GJ mark.
 - Average prices expected to be paid under producer GSAs in the southern states for supply in 2020 and 2021 have fallen, reflecting a fall in prices in fixed-price GSAs and the impact of low oil prices on oil-linked GSAs. Notably, average prices payable under producer GSAs in 2021 in the southern states fell below \$8/GJ.
 - Average prices in recently executed retailer GSAs were lower than those entered into up to August 2019, with average GSA prices for 2020 supply below \$10/GJ, and average prices in 2021 expected to be less than \$10.50/GJ.
- In the final months of 2019 and early 2020, the LNG producers entered into arrangements to sell 18 spot cargoes at prices well below those observed in the domestic market.
- Prices in facilitated markets have fallen significantly over the later months of 2019 and early 2020. There has also been an increase in trading in Victorian Declared Wholesale Gas (DWGM) futures, while trading volumes in Queensland and southern facilitated markets have been relatively stable in Q1 2020.

2.2. Introduction

This chapter presents information about wholesale gas prices in the East Coast Gas Market for supply in 2020 and 2021.

The prices reported in this chapter, unless otherwise specified, reflect wholesale gas commodity prices in offers, bids and gas supply agreements (GSAs) with a term of at least 12 months and an annual contract quantity of at least 0.5 PJ, made at arm's length for supply in the East Coast Gas Market.¹⁰⁸ Where average prices are reported, these are quantity-weighted average prices (unless otherwise specified). A more complete explanation of the ACCC's approach to reporting on prices is presented in appendix A.

This chapter separately reports on prices offered by gas producers and retailers. The following entities were classified as 'retailers': Origin Energy, AGL, EnergyAustralia, Alinta Energy, Shell Energy Australia and Macquarie Bank.

2.3. Recent trends in international LNG and oil prices

As previously outlined by the ACCC, LNG spot prices are expected to influence domestic gas prices because they represent a domestic supplier's opportunity cost of supplying gas to the domestic market (where the alternative is exporting the gas as LNG to the Asian LNG spot market). Moreover, prices payable under GSAs that have a Japan-Korea Marker (JKM) linked pricing mechanism will also be responsive to movements in LNG spot prices.¹⁰⁹

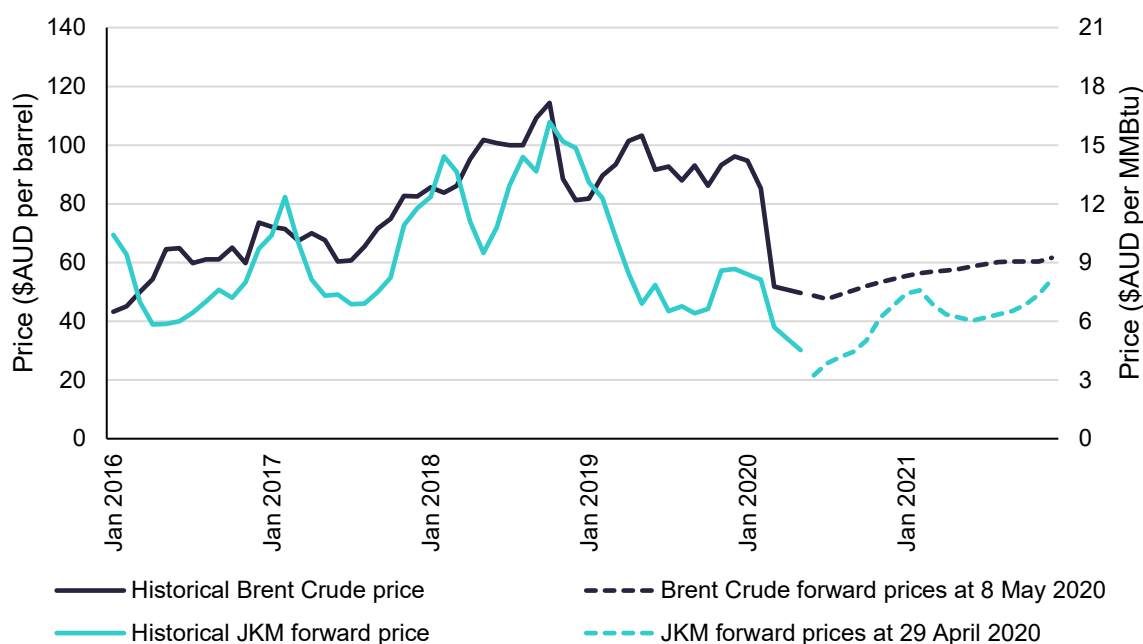
In addition, the price of oil in international markets can directly influence domestic prices through GSAs that have an oil-linked pricing mechanism.

Chart 2.1 shows how oil and LNG spot prices, represented by Brent crude prices and JKM spot prices, have changed in recent years.

¹⁰⁸ The East Coast Gas Market consists of Queensland, New South Wales, Victoria, South Australia, the Australian Capital Territory and Tasmania.

¹⁰⁹ The JKM is S&P Global Platts' price assessment for physical LNG spot cargoes delivered ex-ship into northeast Asia.

Chart 2.1: Monthly Brent Crude oil and JKM price series, January 2016 to December 2021



Note: JKM data based on Historical Platts JKM® Forward Price assessments and ICE's JKM futures series (as published on 29 April 2020). Brent data based on ICE's Brent Crude Oil futures series (as published on 8 May 2020).

Source: ACCC analysis of information obtained from the U.S Energy Information Administration's 'Europe Brent Spot Price FOB' series, S&P Platts Global, ICE.

Chart 2.1 shows that JKM spot prices fell significantly between late 2018 and early 2020, and more generally, that recent LNG spot prices are well below those observed in previous years. The JKM futures curve shows that, even in the peak northern winter periods, JKM prices are expected to remain below \$9/MMBtu through to the end of 2021. This fall in LNG spot prices is primarily attributable to increasing global LNG supply and subdued demand, particularly arising from the impacts of Covid-19.

Similarly, chart 2.1 shows that international oil prices fell substantially between February and March 2020, as a result of decisions by Russia and Saudi Arabia to increase oil production. The COVID-19 pandemic has also impacted on demand, and has subsequently placed further downward pressure on oil prices. Brent Crude oil prices, for example, fell from a high of US\$70/bbl in early January to a record low of US\$9/bbl on 21 April 2020, before recovering somewhat to be around \$34/bbl by the end of May 2020.

As noted in section 2.6, a number of retailers and C&I users in the East Coast Gas Market have entered into GSAs that are linked to international oil or LNG prices. The trends outlined in chart 2.1 can therefore be expected to influence the prices payable under those GSAs. The recent changes in international LNG and oil prices also provide important context for the trends in domestic pricing discussed in the remainder of this chapter.

2.4. Prices offered for supply in 2020 and 2021 softened towards the end of 2019

This report marks the fourth time we have reported on offers made and bids received by suppliers in the East Coast Gas Market for gas supply in 2020. We extend our previous coverage with the addition of information on offers made and bids received by gas suppliers between 23 August 2019 and 20 February 2020.

The ACCC is also reporting, for the first time, on offers made and bids received by suppliers, between 1 January 2019 and 20 February 2020, for supply in 2021.

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 supply end dates
- estimated the price for each offer and bid using the pricing mechanisms specified 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
- calculated the price for each oil or LNG-linked offer and bid based on a simple monthly average of daily observations, in the month the offer or bid was made, of future prices over the specific year of supply (such as 2020).

See appendix A for more information on the ACCC's approach to reporting on prices.

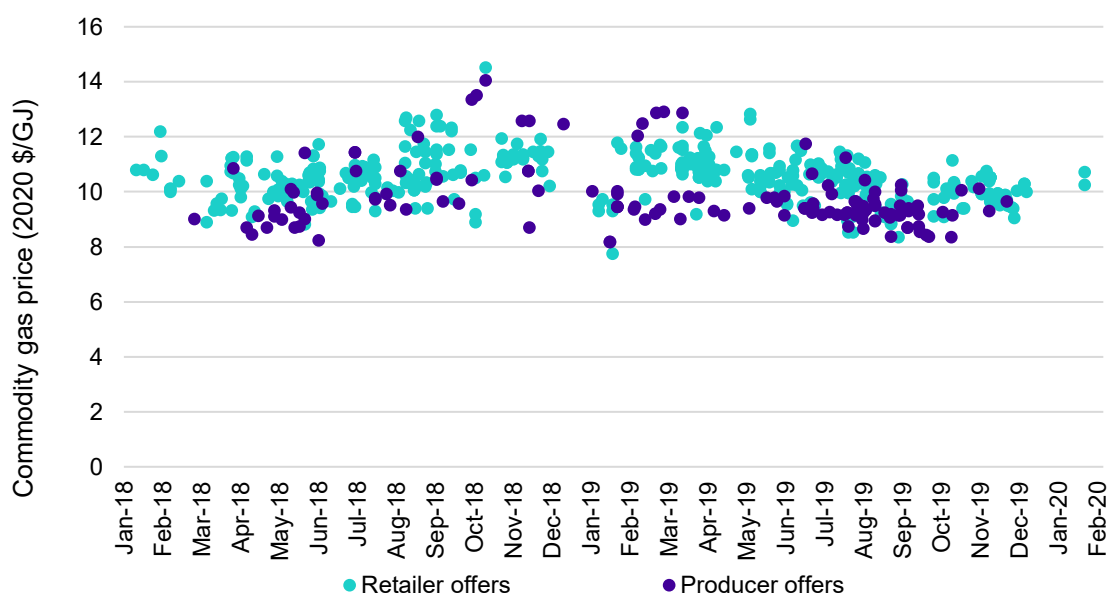
In addition, recognising that the Queensland Government recently awarded a tenement that imposes a condition to supply domestic manufacturers only, the ACCC has excluded those bids and offers where it is clear that the gas to be supplied originated from this tenement. Prices observed in these offers and bids may not be comparable to other prices in the East Coast given the limited number of potential purchasers of this gas. The ACCC has included offers and bids for gas produced in other tenements that have domestic supply conditions as these conditions permit the sale of gas to a wider number of potential buyers, including retailers.

Analysis of offer and bid prices throughout this chapter is intended to provide an indication of price trends over time. As explained in appendix A, 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.

2.4.1. Prices offered for supply in 2020

Chart 2.2 shows offers made by producers and retailers for 2020 supply over the period from 1 January 2018 to 20 February 2020.

Chart 2.2: Gas commodity prices offered for 2020 supply in the East Coast Gas Market



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 0.5PJ per annum and a term of at least 12 months.

Note: Not all price offers in the chart are for unique combinations of seller and buyer. Some offers may reflect ongoing follow-up offers that were made from the same seller and buyer after a previous offer did not result in a GSA.

Chart 2.2 shows that, following a slight upward trend in producer offer prices over 2018, the range of producer offers narrowed over the first half of 2019, with most offers falling between \$9–10/GJ (compared to \$8–12/GJ for most offers made in 2018).¹¹⁰ Since July 2019, there has been a slight downward trend in prices offered by producers, with more offers made in the \$8–9/GJ range, and fewer offers made above \$10/GJ. This was observed across multiple producers, and is not attributable to any individual producer. Between October and December 2019, however, the number of offers made by producers for 2020 supply decreased.

Due to the continued decline of Brent crude oil prices, offers for gas supply with oil-linked pricing mechanisms no longer form the upper range of producer offer prices as they did in 2018.¹¹¹ Further, since August 2019 there has also been a general decline in the level of pricing in fixed-price offers from producers.

Similarly, throughout 2018 there was a slight upward trend in prices offered by retailers (where most prices were within the range of \$9–13/GJ), followed by a moderate decline across the range of retailer prices throughout 2019. Since August 2019, the majority of prices offered by retailers have fallen within the range of \$9–11/GJ, with a small number of offers made below \$9/GJ. Similarly to producers, this downward trend was observed among multiple retailers.

Table 2.1 presents analysis of recent offers made and bids received by gas producers for gas supply to all buyers in 2020. The table compares the offers made and bids received over three periods:

- 24 January 2019 to 24 April 2019 (period 1)

¹¹⁰ As noted in the ACCC's January 2020 report, there were a small number of oil-linked offers made in 2018 that were in excess of \$12/GJ (which reflected high expected future oil prices in 2018).

¹¹¹ ACCC, *Gas Inquiry Interim Report*, January 2020.

- 25 April 2019 to 22 August 2019 (period 2)
- 23 August 2019 to 20 February 2020 (period 3).

Table 2.1: Recent offers made and bids received by producers for gas supply in 2020 (all buyers)

Period 1: 24 January 2019 to 24 April 2019	Offers	Bids
Number of offers or bids	21	46
Gas commodity price range (\$/GJ)	9.00–12.91	8.00–12.59
Quantity weighted average gas commodity price (\$/GJ)	10.44	9.54
Period 2: 25 April 2019 to 22 August 2019	Offers	Bids
Number of offers or bids	43	31
Gas commodity price range (\$/GJ)	8.67–11.75	7.50–10.69
Quantity weighted average gas commodity price (\$/GJ)	9.60	9.19
Period 3: 23 August 2019 to 20 February 2020	Offers	Bids
Number of offers or bids	28	12
Gas commodity price range (\$/GJ)	8.35–10.26	6.60–9.45
Quantity weighted average gas commodity price (\$/GJ)	9.17	8.53

Source (periods 1 & 2): ACCC, Gas Inquiry 2017–2025 Interim Report, January 2020, table 2.1.

Source (period 3): ACCC analysis of offer and bid information provided by suppliers.

Table 2.1 shows that the quantity-weighted average price offered by producers to all buyers, as well as the minimum and maximum prices offered, declined consistently over 2019 and the early months of 2020. In line with the trend observed in chart 2.2, the quantity-weighted average price offered by producers in period 3 (183 days) was \$0.43/GJ lower than in period 2 (120 days). The average price of bids received by producers from all users has similarly declined over the periods observed, and was \$0.66/GJ lower in period 3 when compared to period 2.

The average offer made by producers in period 3 was \$0.64/GJ higher than the average bid received by producers in the same period.¹¹² This spread has increased from period 2, where the average offer made by producers was \$0.41/GJ higher than the average bid received by producers. The increase of the bid-offer spread is attributable to a larger decline in the average price of bids received by producers compared to the fall in the average price offered by producers. This difference may reflect different expectations around gas prices between gas producers and buyers.

Table 2.2 presents analysis of offers made and bids received by retailers for gas supply in 2020. The data presented in this table consists of offers made to, or bids received from C&I gas users, during the same periods as table 2.1.

¹¹² As previously reported in the ACCC's January 2020 interim report, this premium is to be expected given that offers made by suppliers are generally higher than bids made by buyers.

Table 2.2: Recent offers made and bids received by retailers for gas supply in 2020 to C&I gas users

Period 1: 24 January 2019 to 24 April 2019	Offers	Bids
Number of offers or bids	73	<5
Gas commodity price range (\$/GJ)	7.75–12.36	7.08–10.82
Quantity weighted average gas commodity price (\$/GJ)	11.07	10.01
Period 2: 25 April 2019 to 22 August 2019	Offers	Bids
Number of offers or bids	84	15
Gas commodity price range (\$/GJ)	8.54–12.83	7.57–10.70
Quantity weighted average gas commodity price (\$/GJ)	10.49	9.32
Period 3: 23 August 2019 to 20 February 2020	Offers	Bids
Number of offers or bids	72	0
Gas commodity price range (\$/GJ)	8.35–10.76	N/A
Quantity weighted average gas commodity price (\$/GJ)	9.97	N/A

Source (periods 1 & 2): ACCC, Gas Inquiry 2017–2025 Interim Report, January 2020, table 2.2

Source (period 3): ACCC analysis of offer and bid information provided by suppliers

Table 2.2 shows that throughout 2019 and the early months of 2020, there was a consistent decline in both quantity-weighted average prices offered by retailers to C&I users, and bids received from C&I users. The average price offered by retailers to C&I users was \$0.52/GJ lower in period 3 when compared to period 2, and fell below \$10/GJ for the first time since the ACCC began reporting these figures.

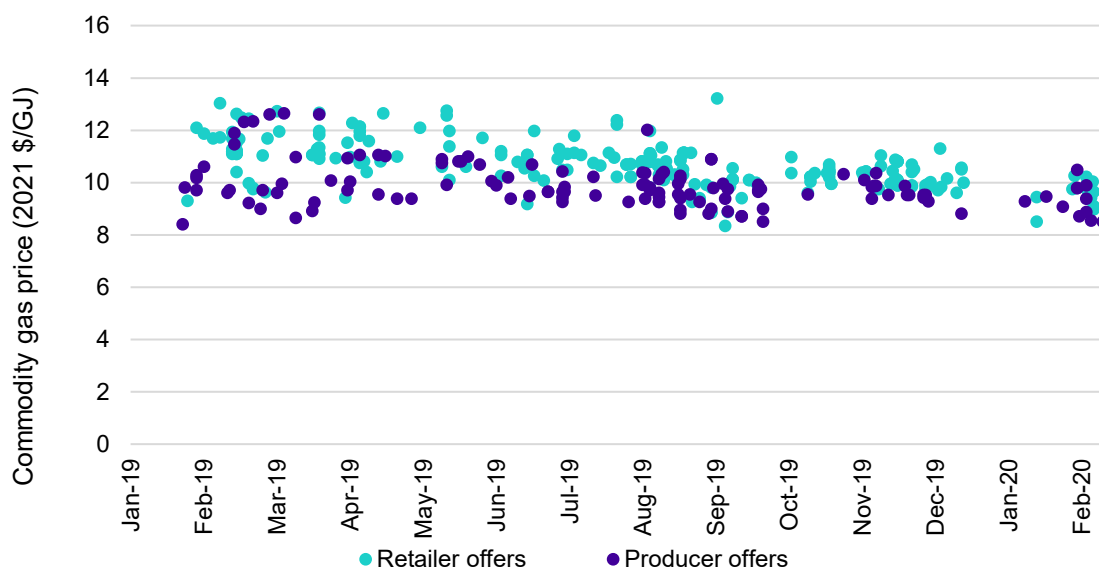
The range of prices offered to C&I users by retailers has narrowed consistently over the three periods covered in table 2.2. The decline in the range of prices offered by retailers is largely attributable to a greater decline in prices at the upper end of the range, as seen in chart 2.2.

In period 3 there were no bids for 2020 gas supply received by retailers from C&I users (that met the criteria set out earlier in this chapter and in appendix A).

2.4.2. Prices offered for gas supply in 2021

This is the first time that the ACCC has reported on offers made and bids received by suppliers in the East Coast Gas Market for 2021 supply (chart 2.3). This analysis is intended to provide an indication of how the price of gas offered by suppliers has evolved over the period 1 January 2019 to 20 February 2020.

Chart 2.3: Gas commodity prices offered for 2021 supply in the East Coast Gas Market



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 0.5PJ per annum and a term of at least 12 months.

Note: Some multi-year offers may be present in both chart 2.2 and 2.3. Similar to chart 2.2, not all offers in the following analysis are for unique combinations of supplier and buyer and may represent further offers between parties if a previous offer did not result in the execution of a GSA.

Chart 2.3 shows that between January 2019 and August 2019, most producer offers were within the range of \$8/GJ to \$11/GJ, with some oil-linked offers in excess of \$11/GJ. Since August 2019, the range of prices offered by producers has narrowed, with most prices falling largely within the range of \$8/GJ to \$10/GJ. Similarly to offers for 2020 gas supply, a reduction in Brent crude oil prices and a slight decline in fixed-price offers has resulted in fewer prices offered by producers in excess of \$10/GJ.

In the first half of 2019, retailer offers fell largely within the range of \$9–13/GJ, before a decline in pricing over the second half of 2019 resulted in fewer retailer offers in excess of \$11/GJ, with the majority of offers falling between \$9/GJ and \$11/GJ.

Table 2.3 compares the offers made and bids received by gas producers for gas supply in 2021 to all buyers. The table compares offers made and bids received over two periods:

- 1 January 2019 to 22 August 2019 (period 1)
- 23 August 2019 to 20 February 2020 (period 2).

Table 2.3: Recent offers made and bids received by producers for gas supply in 2021 (all buyers)

Period 1: 1 January 2019 to 22 August 2019	Offers	Bids
Number of offers or bids	80	94
Gas commodity price range (\$/GJ)	8.40–12.64	7.29–12.38
Quantity weighted average gas commodity price (\$/GJ)	10.37	9.75
Period 2: 23 August 2019 to 20 February 2020	Offers	Bids
Number of offers or bids	53	22
Gas commodity price range (\$/GJ)	8.15–10.90	7.19–10.27
Quantity weighted average gas commodity price (\$/GJ)	9.71	9.01

Source (periods 1 & 2): ACCC analysis of offer and bid information provided by suppliers.

Table 2.3 shows that both prices offered and bids received by producers for gas supply in 2021 slightly declined throughout 2019. The average price offered in period 2 (181 days) was \$0.66/GJ lower than period 1 (233 days), and the average bid received by producers in period 2 was \$0.74/GJ lower when compared to period 1. The range of both prices offered and bids received by producers narrowed in period 2 when compared to period 1, largely due to declining prices at the higher end of the observed range.

Table 2.4 presents analysis of offers made and bids received by retailers for gas supply in 2021. The data presented in this table consists of offers made to, or bids received from C&I users, during the same periods as table 2.3 above.

Table 2.4: Recent offers made and bids received by retailers for gas supply in 2021 to C&I users

Period 1: 1 January 2019 to 22 August 2019	Offers	Bids
Number of offers or bids	123	10
Gas commodity price range (\$/GJ)	9.30–13.04	6.94–10.97
Quantity weighted average gas commodity price (\$/GJ)	11.13	9.62
Period 2: 23 August 2019 to 20 February 2020	Offers	Bids
Number of offers or bids	90	<5
Gas commodity price range (\$/GJ)	8.35–13.22	N/A
Quantity weighted average gas commodity price (\$/GJ)	10.11	10.12

Source (periods 1 & 2): ACCC analysis of offer and bid information provided by suppliers.

Table 2.4 shows that the quantity-weighted average price offered to C&I users by retailers for 2021 supply declined throughout 2019, and were around \$1/GJ lower in period 2 when compared to period 1. The range of prices offered by retailers to C&I users for 2021 supply widened in period 2 when compared to period 1, however this increase is due to a single offer impacting the upper bounds of the range.

Fewer than 5 bids for 2021 gas supply were received by retailers from C&I users in period 2. The average bid received was about \$0.50/GJ more expensive in period 2 than period 1 (largely due to a single expensive bid holding the quantity weighted average up).

2.4.3. Recent gas market price trends in light of the COVID-19 pandemic

The analysis on prices offered for gas supply in 2020 and 2021, presented above, is based on data provided by suppliers up to 20 February 2020. Given recent market developments, the ACCC has since consulted with suppliers and C&I users to seek further information on more recent gas market price trends.

Feedback from gas users and suppliers, albeit anecdotal, suggests that since February 2020, prices have declined even further than previously discussed in section 2.4.2. The ACCC has seen evidence that some suppliers are making offers for 2021 supply in Queensland at pricing below \$7/GJ, and offers in the southern states with pricing between \$7–8/GJ, a noticeable decline at the lower end of prices observed between August 2019 and February 2020. However, feedback suggests that some prices being offered are still relatively high, within the range of \$9–11/GJ, which is consistent with the level of prices presented in section 2.4.2.

The reported decline in prices offered may reflect changes in LNG and oil prices, and may, in part, reflect changes in the demand for gas in the east coast. Some respondents noted that in response to the COVID-19 pandemic, gas users are prioritising management of their changing short-term gas needs and had therefore delayed entering into new GSAs for 2021. As a result, fewer gas contracts have been executed in recent months, which may be a contributing factor to an observed decline in gas prices.

While the feedback suggests that there has been a decline in domestic gas prices over recent months, we note that these prices are still relatively high when compared to contemporaneous expectations of LNG netback prices, as discussed further in the following sections.

2.5. The disparity between LNG netback price expectations and domestic price offers has widened

In its January 2020 report, the ACCC compared offers for 2020 supply against LNG netback price expectations for 2020 up to August 2019. This section provides an update on prices offered for 2020 relative to 2020 LNG netback price expectations, and reports for the first time on prices offered for 2021 supply relative to expectations of 2021 LNG netback prices.

Specifically, this section compares:

- prices offered for supply in 2020 between 1 January 2018 and February 2020 with expectations of 2020 LNG netback prices as at the time the offer was made and estimated costs of gas production, which are based on the estimated breakeven gas price of the marginal supplier of gas in Queensland (as at 2017)
- prices offered for supply in 2021 between 1 January 2019 and February 2020 with expectations of 2021 LNG netback prices as at the time the offer was made and estimated costs of gas production, which are based on the estimated breakeven gas price of the marginal supplier of gas in the southern states (as at 2017).

See appendix A for more information on the ACCC's approach to the analysis in this section.

As noted in previous reports, information obtained by the ACCC from suppliers in the east coast indicates that suppliers are unlikely to use expected future LNG spot prices to assess prices in domestic contracts with a term beyond three years. In part, this is due to the

volatility in Asian LNG markets (see section 2.4.1 below), and the fact that LNG spot futures markets have little to no liquidity beyond a few years into the future.

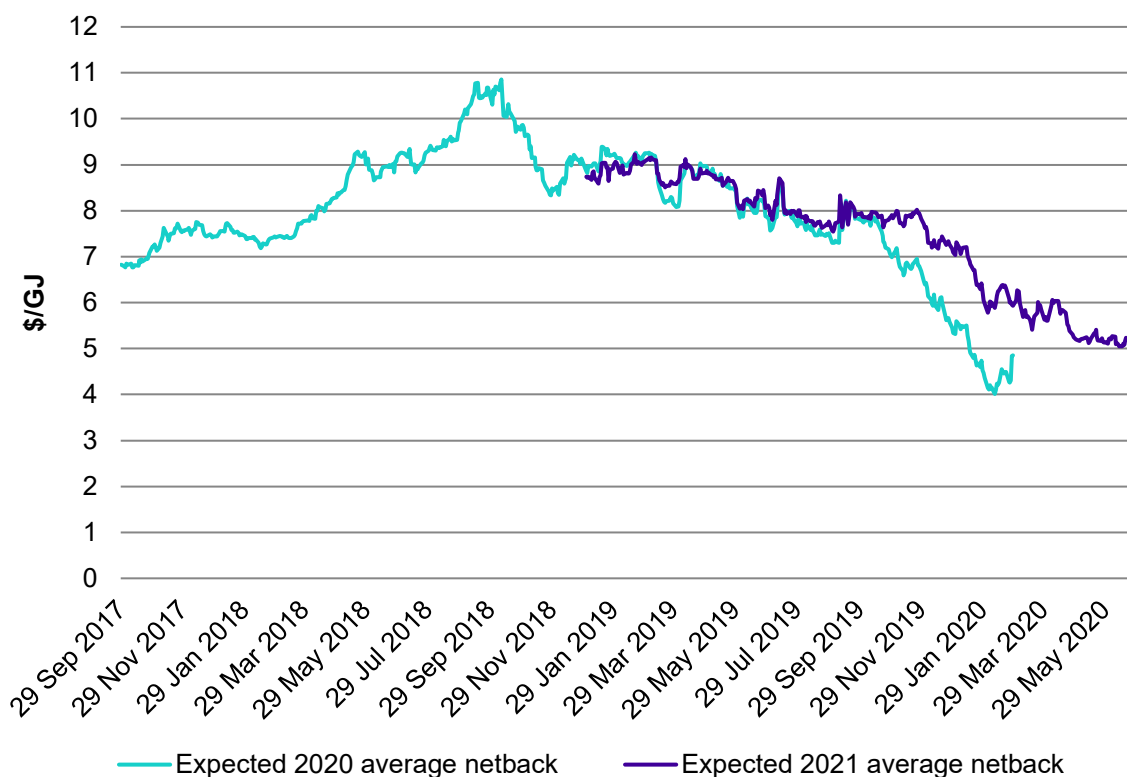
On this basis, the ACCC has included in the analysis in this section only those offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have also been excluded from this analysis, as expectations around future oil and LNG prices can be markedly different.

Sections 2.4.2 and 2.4.3 present the findings of our comparison for prices offered in Queensland and the Southern States for supply in 2020.

2.5.1. LNG netback price expectations for 2020 and 2021 continued to fall over 2019

Chart 2.4 shows how expected LNG netback prices for 2020 and 2021 have changed over the period from 1 January 2018 to mid-2020. Each point in the chart represents a daily average of expected LNG netback prices across the entirety of 2020 and 2021. This differs from the LNG netback prices presented in sections 2.4.2 and 2.4.3 below, which present expected 2020 and 2021 LNG netback prices on a monthly average basis.¹¹³

Chart 2.4: Expected average LNG netback prices at Wallumbilla for 2020 and 2021



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

Note: Forward shipping estimates were not available for all of 2020 prior to 7 December 2018. Expected LNG netback prices for 2020 prior to 7 December 2018 use a combination of 2019 and 2020 forward shipping costs as an input.

¹¹³ Chart 2.3 differs from the ACCC's regular publication of LNG netback prices, in that it shows how expectations of average LNG netback prices for the entirety of 2020 and 2021 have changed over time, rather than showing expected forward prices for each month. This provides a basis for comparing offers for 2020 and 2021 gas supply against expected LNG netback prices (as in sections 2.4.2 and 2.4.3 below).

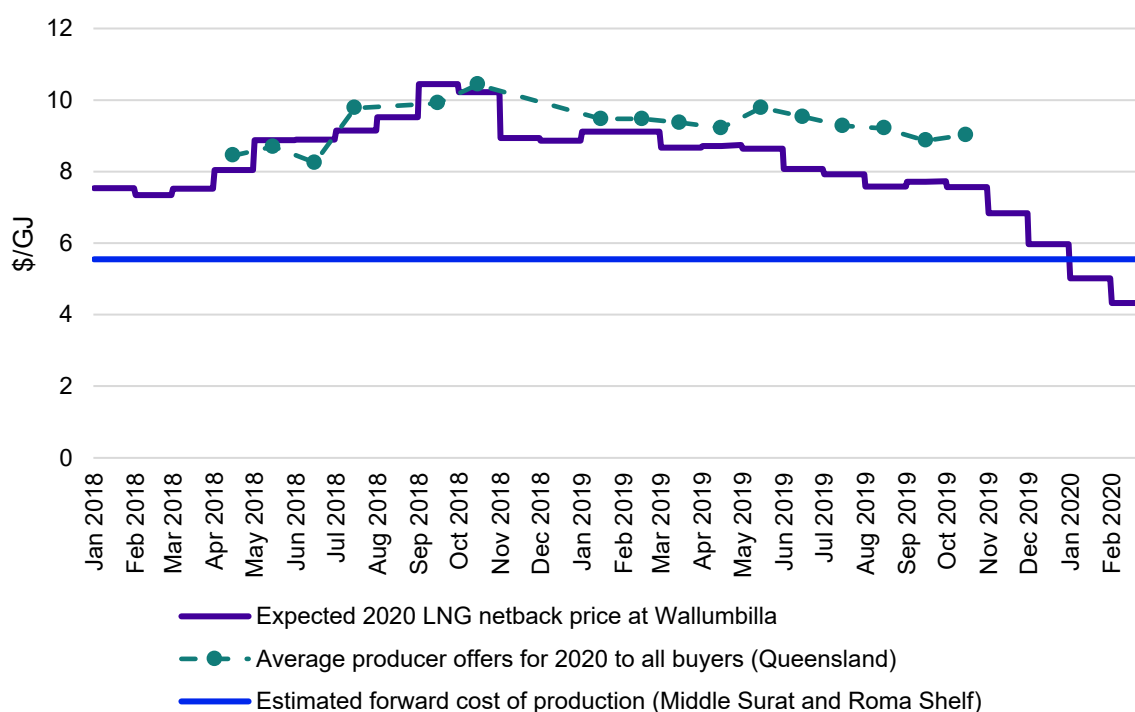
Chart 2.4 shows that expected 2020 LNG netback prices exhibited a downward trend over 2019, falling from around \$9.00/GJ at the start of 2019 to less than \$5.50/GJ by December 2019. This downward trend, which was more pronounced in the second half of 2019, reflected increasing LNG supply capacity, particularly in the United States, and relatively subdued LNG demand due to mild winter weather in Asia and high global LNG storage. The sharp declines in November and December 2019 may have also reflected early impacts of COVID-19 on LNG demand.

Expected LNG netback prices for 2021 followed a similar trend, with expected LNG netback prices in 2021 being in line with those expected for 2020 until the end of October 2019. Expected 2021 LNG netback prices continued to fall over late 2019 and early 2020, but not to the same extent as expected 2020 prices—expected 2021 LNG netback prices largely remained with the range of \$5.50–6.50/GJ over early 2020.

2.5.2. Prices offered for 2020 supply relative to expected 2020 LNG netback prices

This section compares prices offered for 2020 and 2021 supply in Queensland to contemporaneous expectations of 2020 and 2021 LNG netback prices and estimated forward costs of production.

Chart 2.5: Averages of monthly gas commodity prices offered by Queensland producers for 2020 supply against contemporaneous expectations of LNG netback prices



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

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

Chart 2.5 shows that the disparity between domestic prices offered in Queensland (for 2020 supply) and expected 2020 LNG netback prices, which initially emerged in March 2019 and was noted in the ACCC’s January 2020 report, has persisted into the later months of 2019. The disparity in the latter months has also been greater than that observed in early 2019. While prices offered have softened slightly over 2019, they have not reflected continuing falls

in expected 2020 LNG netback prices (at a time when expectations around 2020 LNG netback prices would likely have been less uncertain).

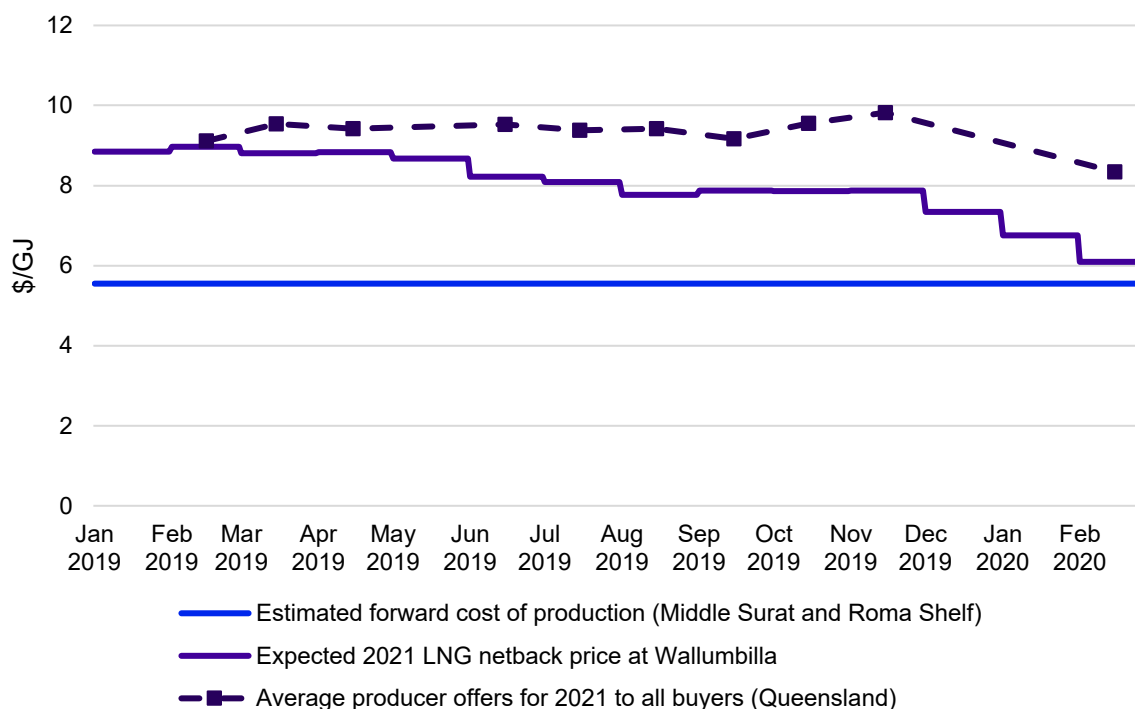
The difference between domestic price offers in Queensland and expected 2020 LNG netback prices was between \$1–1.80/GJ over the period from May to October 2019, with this difference being reflected in offers made by a range of suppliers in Queensland. For some offers, however, this difference may reflect, in part, transport costs associated with supplying gas to locations other than Wallumbilla.

A disparity between domestic prices offers and expected LNG netback prices was also observed for supply in 2021.

Chart 2.6 shows that the disparity between quantity-weighted average prices offered in Queensland and expected LNG netback prices in 2021 began to emerge in March 2019 (at the same time as that observed for offers for supply in 2020).

While average monthly prices offered remained within the range of \$9–10/GJ over 2019, the average for February 2020 fell below \$8.50/GJ. Despite this, the February 2020 average was more than \$2/GJ higher than expected 2021 LNG netback prices, and was above that observed in any month in chart 2.5. That is, the disparity was greater, at least in some months, for 2021 supply when compared to that for 2020 supply. The disparity observed in February 2020 is also the largest disparity observed by the ACCC.

Chart 2.6: Averages of monthly gas commodity prices offered by Queensland producers for 2021 supply against contemporaneous expectations of LNG netback prices¹¹⁴



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

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

¹¹⁴ This chart shows expected average LNG netback prices in 2021 up to the end of February 2020. However, as shown in chart 2.4, expected average LNG netback prices in 2021 have fallen since February 2020, and by June 2020 were just above \$5/GJ.

The similarity between the trends observed in charts 2.5 and 2.6 may reflect the inclusion of the same offers in both charts (that is, single offers that include supply in both 2020 and 2021 with similar pricing for each year), or alternatively may reflect offers linked to LNG spot prices (expected LNG netback prices in 2020 and 2021 were broadly similar until the end of October 2019).

2.5.3. Prices offered in the southern states

This section compares quantity-weighted average prices offered, on a monthly basis, to the range of prices that would be expected to be observed under the bargaining framework outlined in previous ACCC reports (see appendix A for more information). Under this framework, the pricing dynamics in the southern states are different from those in Queensland.

In particular, prices in the southern states 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, and
- 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.

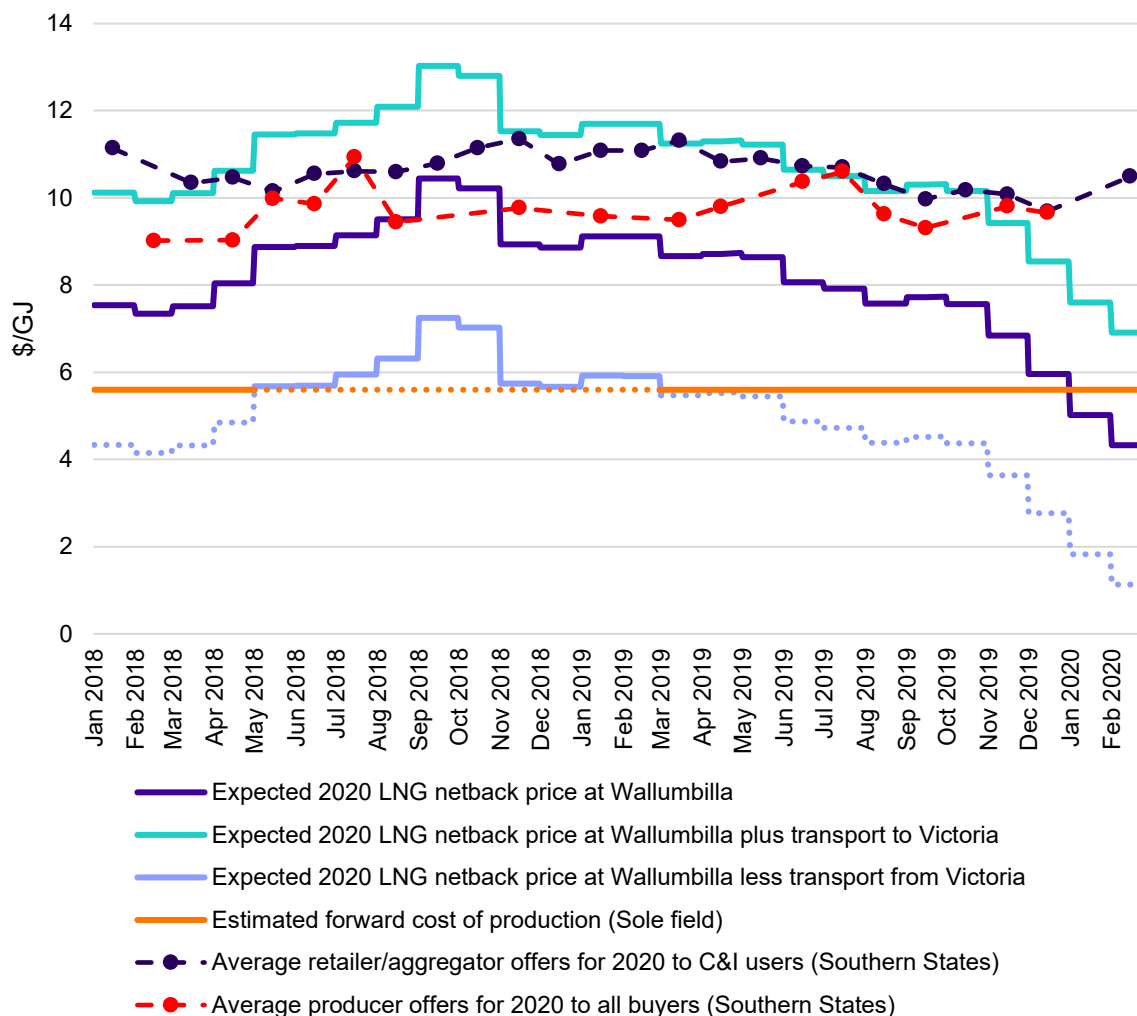
Chart 2.7 shows quantity-weighted average prices offered by suppliers in the southern states, between January 2018 and February 2020, for supply in 2020 compared to the range within which gas prices would be expected to fall using the bargaining framework.

The upper end of the range is the buyer alternative in Victoria—indicative of the highest price that would be expected to be offered in the southern states under the bargaining framework—which is derived by taking averages of expected LNG netback prices at Wallumbilla for a given year, 2020 in this instance, and adding indicative pipeline tariffs to Melbourne.¹¹⁵ Buyer alternative prices in other locations in the southern states would be expected to lie between LNG netback prices at Wallumbilla and Victorian buyer alternative prices. The lower end of the range is the seller alternative in Victoria, determined by the higher of:

- the averages of expected LNG netback prices at Wallumbilla for a given year, 2020 in this instance, less indicative pipeline tariffs from Melbourne to Wallumbilla
- the cost of production of the marginal source of supply.

¹¹⁵ These tariffs are updated for each report based on invoice data provided by pipeline operators (see chapter 4).

Chart 2.7: Averages of monthly gas commodity prices offered for 2020 supply against contemporaneous expectations of LNG netback prices (southern states)



Source: ICE, Argus, Core Energy, ACCC analysis of information provided by suppliers and pipeline operators.

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

In the January 2020 report, the ACCC observed that quantity-weighted average prices offered by producers in the southern states had trended upwards over the second quarter of 2019 (although, as noted in the January 2020 report, the high June and July averages reflected several high priced offers for gas supply with a high degree of flexibility, which increased those averages).

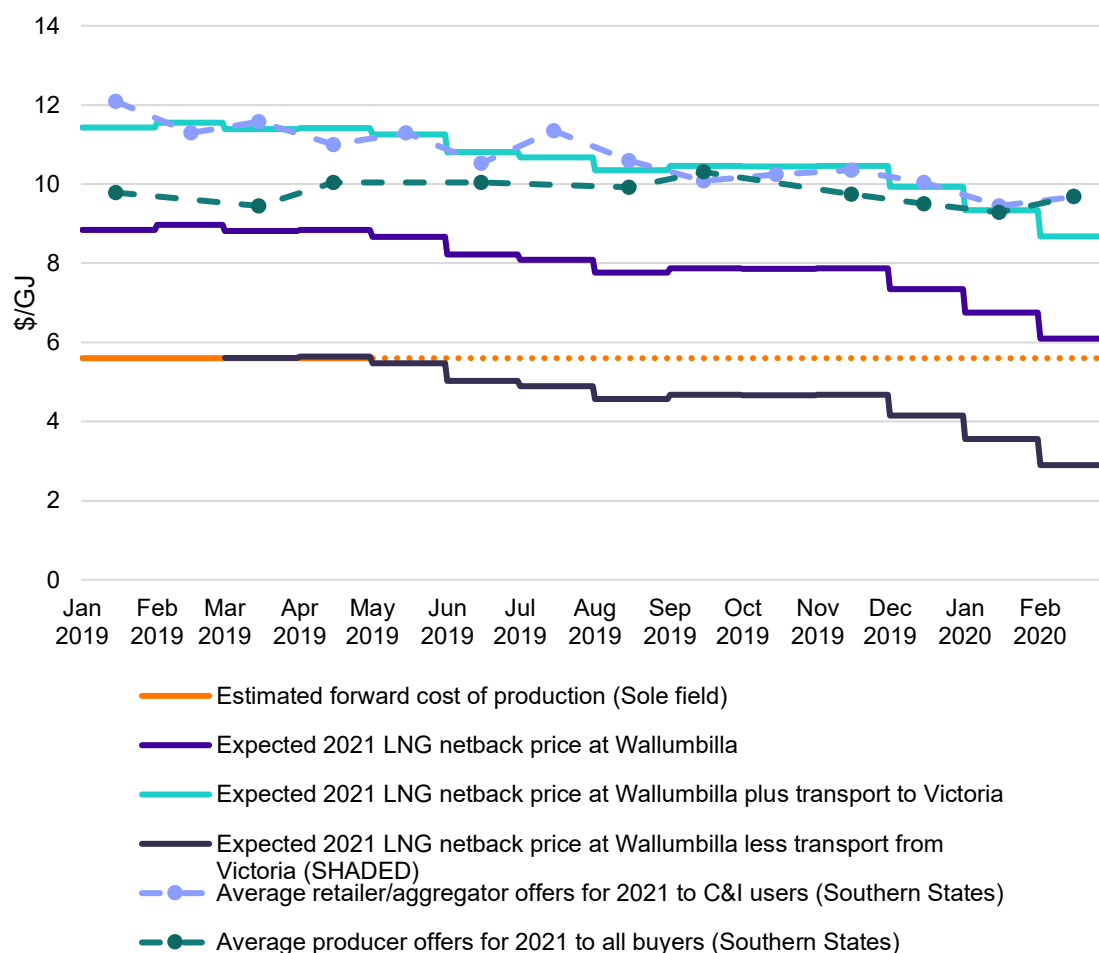
Chart 2.7 shows that prices offered by producers, in the period between August and December 2019, remained within the range of \$9–10/GJ. If the high priced offers in June and July 2019 were removed, quantity-weighted average prices offered by producers in the southern states would have been in the range of \$9–10/GJ over the entirety of 2019. This relative stability in prices offered was observed despite significant falls, over this period, in expected 2020 LNG netback prices.

Quantity-weighted average prices offered by retailers trended downwards over the latter half of 2019, although average prices remained above \$10/GJ in all but one month in 2019. The downward trend in average retailer offer prices coincided with falling LNG netback price expectations, with average offers being in line with the buyer alternative across much of

2019. In November and December 2019, however, average retailer offers were above the buyer alternative which, as noted earlier, is the maximum price expected to be observed under the bargaining framework.

Chart 2.8 shows quantity-weighted average prices offered by suppliers in the southern states between January 2019 and February 2020 for supply in 2021 compared to the range within which gas prices would be expected to fall using the bargaining framework.

Chart 2.8: Averages of monthly gas commodity prices offered for 2021 supply against contemporaneous expectations of LNG netback prices (southern states)



Source: ICE, Argus, Core Energy, ACCC analysis of information provided by suppliers and pipeline operators.

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

Chart 2.8 shows that quantity-weighted average producer offers were relatively stable over the period from January 2019 to February 2020, with the averages over that period falling within the range of \$9.30–10.30/GJ.

As in Queensland, prices offered by producers in the southern states do not appear to have been responsive to falling expectations around 2021 LNG netback prices—quantity-weighted average prices have remained range bound at a time when LNG netback price expectations have decreased significantly. As a result, by the end of 2019 average producer price offers were in line with the buyer alternative.

Quantity-weighted average prices offered by retailers, however, exhibited a downward trend, albeit moderate, falling from more than \$12/GJ in January 2019 to less than \$9.50/GJ in February 2020. On this basis, it appears that average retailer offers for 2021 supply in the southern states have been more responsive to movements in expected LNG netback prices and the buyer alternative. However, it is not yet clear if there is a link between retailer price offers and the buyer alternative. The ACCC will further investigate this pricing behaviour over 2020.

While prices offered have moderated somewhat, the disparity between domestic price offers and expected LNG netback prices has persisted, with the difference for 2021 supply greater than that observed for 2020 supply. In a well-functioning market, the ACCC expects that domestic price offers would follow falling LNG netback price expectations down, as they did when those expectations were increasing. In a market where LNG prices are well below domestic prices, domestic suppliers would, in principle, seek to divert supply away from LNG spot markets and towards the domestic market. This, in turn, would put downward pressure on domestic prices.

However, the recent pricing behaviour of suppliers in Queensland suggests that, while LNG producers have in recent years contributed more gas to the domestic market than they have taken out (see section 1.8.3), insufficient gas has been diverted to the domestic market to bring domestic prices in line with expected LNG netback prices. At the same time, the ACCC has observed LNG producers enter into arrangements to sell LNG spot cargoes at prices well below those in the domestic market—in total, 18 LNG spot cargoes were sold in the period from September 2019 to February 2020 (although some of these LNG cargoes will be delivered over the course of 2020).¹¹⁶

As flagged in the January 2020 report, the ACCC will investigate factors that may be influencing domestic prices and contributing to the disparity with export prices. As part of this work we will consider the extent to which competition, or the lack thereof, is contributing to what we have observed. To inform this work, in May 2020 the ACCC issued mandatory information notices to a range of suppliers seeking information and documents related to their pricing and marketing strategies.

The ACCC will report on relevant findings and as relevant consider the need for any additional policy measures that could improve outcomes in the East Coast Gas Market.

2.6. Prices agreed to under GSAs have also softened

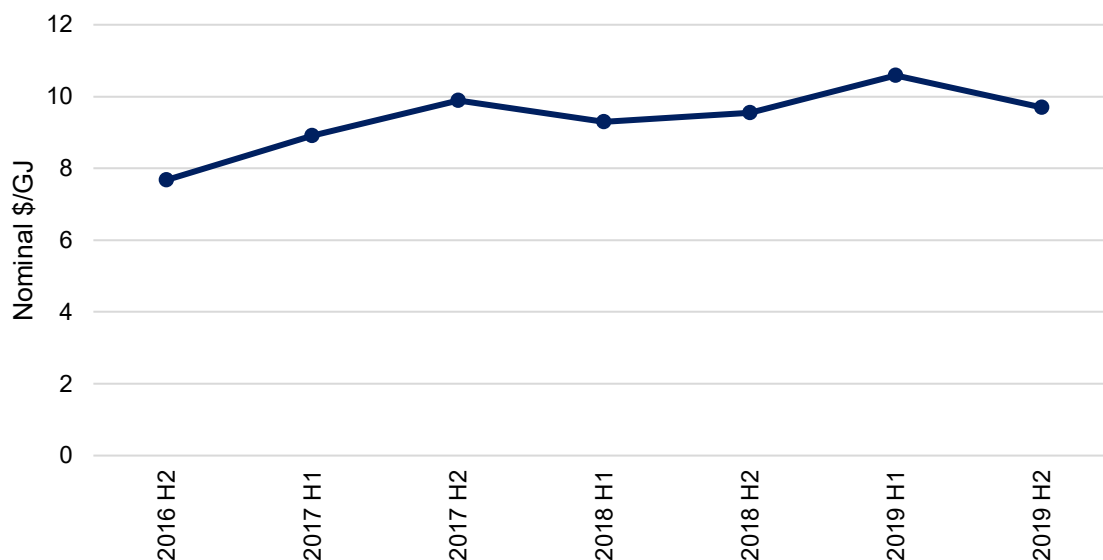
2.6.1. Average prices under recently executed fixed price GSAs fell below \$10/GJ, but are still high

The analysis in this section provides information on how prices in fixed price GSAs entered into by producers and retailers with C&I users have evolved over time.

Chart 2.9 presents quantity-weighted average prices under GSAs executed in half yearly intervals from the second half of 2016 to the second half of 2019 in the East Coast Gas Market. GSAs included in the averages are executed at arm's length, have an annual contracted quantity of at least 0.5 PJ, a term of at least 12 months, and have fixed prices (that is, GSAs with pricing mechanisms linked to international LNG or oil prices are excluded).

¹¹⁶ The quantity of gas sold in an LNG spot sale is typically in excess of 3 PJ.

Chart 2.9: Half yearly quantity-weighted average wholesale gas commodity prices under fixed price GSAs



Source: ACCC analysis of information provided by suppliers.

Chart 2.9 shows that prices agreed to by C&I gas users in newly executed GSAs (with fixed prices) rose sharply between the second half of 2016 and the second half of 2017. Quantity-weighted average GSA prices subsequently softened to between \$9–10/GJ in 2018 as more gas was made available to the domestic market following the signing of the Heads of Agreement between the Australian Government and LNG producers in October 2017.

However, the first half of 2019 saw the quantity-weighted average price under fixed-price GSAs increase again, up by almost 11 per cent from the second half of 2018. This increase was due to a combination of two factors. Average GSA prices agreed between retailers and C&I users increased over the period, as did the relative proportion of gas to be supplied to C&I users under retailer GSAs.

Between the first and second half of 2019, average prices executed under fixed price GSAs decreased by around 8.5 per cent. Again, this was primarily due to two factors. Average prices agreed between retailers and C&I users fell by around 5.4 per cent and the relative proportion of gas to be supplied under producer contracts increased, thereby bringing down the quantity-weighted average GSA price.

If the data in chart 2.9 were to be disaggregated into quarterly prices, it would show that the quantity-weighted average price in the third quarter of 2019 remained over \$10/GJ, increasing slightly from the second quarter of 2019. Then, in the fourth quarter, the quantity-weighted average price decreased by around 10 per cent (from that observed in the third quarter). This decrease reflected a decline in both retailer and producer prices, and an increase in the relative volume of producer GSAs being entered into.

2.6.2. Prices agreed under GSAs for supply in 2020 and 2021 also softened

The analysis in this section covers GSAs for supply in 2020 that were entered into between 1 January 2018 and 20 February 2020 and GSAs for supply in 2021 that were entered into between 1 January 2019 and 20 February 2020. While the ACCC has previously reported on prices under GSAs for supply in 2020, this is the first time the ACCC has reported on GSAs for supply in 2021.

As outlined in appendix A, the GSAs included in the analysis in this sections are those that:

- have an annual contract quantity of 0.5 PJ and a contract term of 12 months or more
- are executed at arm's length
- are between retailers and C&I users for the analysis of retailer GSA pricing.

As with the analysis of bids and offers, we estimate average prices under GSAs using assumptions relating to a number of key variables, including the AUD/USD exchange rate, inflation, and the price of oil and LNG on international spot markets. However, whereas bids and offers are priced using expectations of these variables at the bid or offer date, this analysis involves pricing GSAs based on current market expectations for the relevant supply year.

Prices published in this section are not necessarily comparable to the prices previously reported by the ACCC due to changed pricing assumptions. This stems from changes in market expectations, and the inclusion of recently executed GSAs. For instance, a large decline in international oil price expectations may reduce prices under oil-linked GSAs, relative to prices under the same oil-linked GSAs published in a previous report.

GSAs entered into by producers

Table 2.5 shows quantity-weighted average gas prices expected to be paid for supply in 2020 under GSAs entered into by producers.

Table 2.5: Expected 2020 wholesale gas commodity prices under producer GSAs executed between 1 January 2018 and 20 February 2020

Delivery location	Execution period	Average price (\$/GJ)	Price range (\$/GJ)
Queensland	1 Jan 2018–22 Aug 2019	7.01	6.05–9.63
Queensland	23 Aug 2019–20 Feb 2020	8.25	6.44–10.17
Southern States	1 Jan 2018–22 Aug 2019	9.73	8.86–10.82
Southern States	23 Aug 2019–20 Feb 2020	8.96	7.86–9.90

Source: ACCC analysis of information provided by suppliers.

Average prices in Queensland under producer GSAs executed between 23 August 2019 and 20 February 2020 were higher relative to those executed between 1 January 2018 and 22 August 2019 (despite expected 2020 LNG netback prices falling over this period). Prices in the southern states, on the other hand, fell over the same period.

The increase in average prices in Queensland can be explained by the recent execution of a relatively high priced GSA and a decrease in the relative proportion of gas that will be supplied under GSAs linked to international oil and LNG prices.¹¹⁷ Given that expected

¹¹⁷ However, this proportion is not zero, with the GSA priced at \$6.44/GJ, for instance, being oil-linked.

prices under oil and LNG-linked GSAs are lower than prices under fixed-price GSAs¹¹⁸, a decrease in the proportion of supply linked to international oil and LNG prices has resulted in an increase in the average prices expected to be paid under GSAs in Queensland.

In the southern states, the decrease in average prices reflects a general downward trend in pricing in both fixed-price and floating-price GSAs, with the latter period seeing an increase in the proportion of gas contracted at prices below \$9/GJ and no newly executed GSAs with prices above \$10/GJ.

Average prices for 2020 supply in GSAs executed between 1 January 2018 and 22 August 2019, as shown in table 2.5, can also be compared to those reported in table 2.3 of the Gas Inquiry's January 2020 report. For this period, the quantity-weighted average price for supply in Queensland decreased relative to that reported in the January 2020 report (\$8.52/GJ), whereas the average in the Southern States remained unchanged.

In Queensland, a small number of GSAs that constitute a large portion of the period's contracted quantity were linked to international commodity prices. Given the recent decline in the prices of these commodities, as detailed in section 2.3, prices expected to be payable under these GSAs have declined. As such, both the minimum and the average gas commodity price in Queensland declined relative to those published in the January 2020 report.

Table 2.6 shows quantity-weighted average gas prices expected to be paid for supply in 2021 under GSAs entered into by producers.

Table 2.6: Expected 2021 wholesale gas commodity prices under producer GSAs executed between 1 January 2019 and 20 February 2020

Delivery location	Contract type	Average price (\$/GJ)	Price range (\$/GJ)
Queensland	All contracts	8.32	5.78–10.76
Southern States	All contracts	7.81	6.93–10.01
East Coast	Fixed price contracts	9.36	8.06–10.76
East Coast	Oil linked contracts	7.52	5.78–8.05

Source: ACCC analysis of information provided by suppliers.

Average prices under GSAs for 2021 supply in Queensland are marginally higher than average prices under GSAs for supply in 2020 executed between 23 August 2019 and 20 February 2020, whilst the average price in the southern states is significantly lower at \$7.81/GJ.

The decrease in the average price in the southern states is due to a small number of parties recontracting a large quantity of supply for 2021 under contracts linked to international oil prices. None of the producer GSAs for 2020 supply in the southern states executed between 1 January 2018 and 20 February 2020 were oil-linked. In sharp contrast, almost 90 per cent of 2021 supply under GSAs entered into between 1 January 2019 and 20 February 2020 is to be supplied to both retailers and C&I users under oil-linked GSAs which, under current pricing assumptions, are priced significantly lower than fixed-price GSAs.

This is evident in table 2.6, which shows that the substantial decrease in oil price expectations caused the price of oil-linked GSAs to fall well below prices under fixed-price GSAs. Given that a relatively small quantity of gas in Queensland is oil-linked, average 2021 prices in Queensland are expected to be higher than in the southern states. However, if only

¹¹⁸ This follows the recent sharp decline in international oil and LNG prices.

fixed-price GSAs are considered, weighted-average gas prices in both regions are similar, at around \$9.35/GJ.

Further, the majority of oil-linked GSAs executed between 1 January 2019 and 20 February 2020 across the East Coast are between producers and retailers. Whether these relatively low GSA prices lead to lower prices for C&I users will likely depend on the level of competition between retailers.

In both Queensland and the southern states, average prices for supply in 2021 were lower in producer GSAs executed between 23 August 2019 and 20 February 2020 relative to prices in GSAs executed between 1 January 2019 and 22 August 2019.

In Queensland, this decrease was due to the recent execution of an oil-linked GSA, which offset increased average prices under fixed-price GSAs. However, in the southern states, the decrease reflected a decline in pricing for both oil-linked and fixed-price GSAs, with a number of fixed-price GSAs priced around \$9/GJ.

GSAs entered into by retailers and major gas users

Table 2.7 shows quantity-weighted average gas prices expected to be paid for supply in 2020 under GSAs between retailers and C&I and GPG users.

Table 2.7: Expected 2020 wholesale gas commodity prices under retailer GSAs executed between 1 January 2018 and 20 February 2020

Delivery location	Execution period	Average price (\$/GJ)	Price range (\$/GJ)
Queensland	1 Jan 2018–20 Feb 2020	8.97	6.08–10.94
Southern States	1 Jan 2018–22 Aug 2019	10.69	9.19–11.57
Southern States	23 Aug 2019–20 Feb 2020	9.76	9.05–11.18

Source: ACCC analysis of information provided by suppliers.

In Queensland, the average price for 2020 supply under GSAs executed between 1 January 2018 and 20 February 2020 is around \$9/GJ, which is significantly lower than the average price published in table 2.4 of the Gas Inquiry's January 2020 report (\$10.33/GJ). This fall in price reflects the inclusion of a recently executed oil-linked GSA.¹¹⁹

Quantity-weighted average prices for 2020 supply in the southern states under GSAs executed between 23 August 2019 and 20 February 2020 were lower than those under GSAs executed in the preceding period. This reflects the effect of falling oil prices on the price of oil-linked contracts, and also reflects a general decline in prices under fixed-price GSAs, with a number of fixed-price GSAs priced below \$10/GJ.

Table 2.8 shows quantity-weighted average gas prices expected to be paid for supply in 2021 under GSAs entered into between retailers and both C&I and GPG users.

¹¹⁹ The ACCC has not compared weighted-average prices under retailer GSAs executed between 1 January 2018 and 22 August 2019 to those under GSAs executed between 23 August 2019 and 20 February 2020 as there were few GSAs entered into by retailers in Queensland in the later period.

Table 2.8: Expected 2021 wholesale gas commodity prices under retailer GSAs executed between 1 January 2019 and 20 February 2020

Delivery location	Execution period	Average price (\$/GJ)	Price range (\$/GJ)
Southern States	1 Jan 2019–22 Aug 2019	11.18	9.43–11.87
Southern States	23 Aug 2019–20 Feb 2020	10.29	8.42–11.14
East Coast	1 Jan 2019–20 Feb 2020	10.96	8.42–11.87

Source: ACCC analysis of information provided by suppliers.

In the southern states, average prices for 2021 supply were lower under GSAs executed between 23 August 2019 and 20 February 2020 than under GSAs executed in the preceding period. As with GSAs for 2020 supply, this fall primarily reflects the influence of falling oil prices on oil-linked GSAs, but it also reflects a softening of fixed prices.

Consistent with previous observations, the average price of retailer GSAs for supply in 2021 is higher than the average price of producer GSAs. However, this difference decreases if only average prices under fixed price contracts are compared.

2.6.3. Flexibility agreed under GSAs for 2020 and 2021

In this section, we report on the quantity-weighted average of load factors and take or pay multipliers in GSAs. Load factors and take or pay multipliers are key terms and conditions in GSAs that, in practice, provide users with flexibility in how they manage their gas usage. They may also influence the costs of supply and the value to a gas user of the gas supplied under a GSA.

This is because suppliers who enter into flexible GSAs will need to ensure they can supply a quantity of gas, either on a daily basis or over the life of the contract, which the buyer may not actually take. This, in turn, might mean that the supplier needs to reserve gas (at the expense of extra sales), use storage facilities, and maintain sufficient processing and pipeline capacity (where applicable) to deliver the contracted quantity regardless of whether the buyer elects to take the entire contracted quantity.

As such, the value of these non-price terms and conditions in GSAs can be an important qualifier when considering the commodity price of gas under a GSA.

Table 2.9 shows the quantity-weighted average load factor and take or pay multipliers under GSAs for supply in 2020 entered into by producers and retailers.

Table 2.9: Average Load Factor and Take or Pay Multiplier in 2020 under GSAs executed between 1 January 2018 and 20 February 2020

Type of supplier (delivery location)	Load Factor	Take or Pay Multiplier %
Producers (Queensland)	1.05	92
Producers (Southern States)	1.37	95
Retailers (Queensland)	1.16	87
Retailers (Southern States)	1.17	90

Source: ACCC analysis of information provided by suppliers.

The quantity-weighted average load factor under producer GSAs for supply in 2020 has decreased marginally in Queensland and significantly in the southern states compared to

respective load factors reported in table 2.5 of the Gas Inquiry’s January 2020 report (which included GSAs for 2020 supply entered into between 1 January 2018 and 22 August 2019). The decrease in the southern states reflects that a number of newly entered GSAs have a lower load factor (with a lower load factor representing a lower level of flexibility). Further, while the take or pay multiplier is marginally higher in the southern states, it is marginally lower in Queensland (again, compared to GSAs executed between January 2018 and August 2019).

Under retailer GSAs, average load factors and average take or pay multipliers have changed marginally from the averages reported in table 2.6 of the Gas Inquiry’s January 2020 report. However, in both regions, GSAs executed between 23 August 2019 and 20 February 2020 had, on average, moderately higher load factors than the preceding period. Whilst the average take or pay multiplier in the southern states in recently executed GSAs marginally decreased, it marginally increased in Queensland.

Table 2.10 shows the quantity-weighted average load factor and take or pay multipliers under GSAs for supply in 2021 entered into by producers and retailers.

Table 2.10: Average Load Factor and Take or Pay Multiplier in 2021 under GSAs executed between 1 January 2019 and 20 February 2020

Type of supplier (delivery location)	Load Factor	Take or Pay Multiplier %
Producers (Queensland)	1.03	89
Producers (Southern States)	1.00	92
Retailers (East Coast)	1.14	90

Source: ACCC analysis of information provided by suppliers.

The average load factor under producer GSAs in the southern states is moderately lower for supply in 2021 than under recently executed contracts for supply in 2020. This reflects that a number of highly flexible producer contracts for supply in 2020 will expire at the end of 2020. The average take or pay multiplier under producer GSAs in the southern states moderately decreased. For producer GSAs in Queensland, both the average load factor and take or pay under GSAs for supply in 2021 remained relatively unchanged when compared to those under recently executed GSAs for supply in 2020.

In the southern states, the average load factor and the average take or pay multiplier under retailer GSAs for 2021 supply that were executed between 23 August 2019 and 20 February 2020 provide significantly more flexibility than in GSAs executed between 1 January 2019 and 22 August 2019. This is explained by a number of recent contracts including significantly higher load factors, and moderately lower take or pay multipliers.

2.7. LNG spot and additional LNG sales by Queensland LNG producers

This section reports on recent additional LNG sales made by Queensland LNG producers.

In the period from September 2019 to February 2020, the LNG producers sold an additional 18 LNG cargoes, either into LNG spot markets or as additional sales under their long-term contracts. These sales occurred after a period of minimal spot sale activity from the east coast of Australia over calendar year 2019.

The increase in spot and additional LNG sales, from September 2019, may be due to LNG producers producing more gas than their buyers were willing to take under their long-term contracts. As noted in chapter 1, some LNG producers have announced that some of their

contract customers exercised 'Downward Quantity Tolerance' clauses in their contracts, thereby reducing the volumes of LNG they intend to take over 2020. This has potentially resulted in the LNG producers having more excess gas than planned.

LNG producers entered into both fixed-priced and floating price contracts (with some of the latter) linked to JKM, for the sale of spot and additional LNG cargoes. Most of the floating price contracts observed by the ACCC were linked to JKM prices, discounted to reflect shipping costs to Asia (which were borne by buyers of the spot cargoes).

However, these prices are still well below those being offered in the domestic market (see sections 2.4 and 2.5).

There are various reasons why LNG producers may seek to export LNG spot cargoes rather than supply the domestic contract market. First, this gas may have unsuccessfully been offered to the domestic market prior to being exported as LNG (albeit at prices well above LNG netback prices, as noted in section 2.5). Second, exporting LNG discretionary cargoes may present fewer risks than entering into long-term GSAs with domestic buyers (which would require delivery of set volumes to customers on a daily basis). Finally, LNG producers may also face additional costs or barriers in accessing pipeline capacity to transport south (particularly given contractual congestion on the South West Queensland Pipeline (see chapter 4), and storage capacity to manage the daily volumes required to be delivered under domestic GSAs.

Notwithstanding the above, that 18 LNG cargoes were exported at a time when LNG prices sit well below domestic prices is extremely concerning, and as noted earlier in this chapter, raises questions about the level of competition in the market.

Also as noted earlier, the ACCC intends to examine factors that influence the pricing of gas in the East Coast Gas Market, and report back on any relevant findings.

2.8. Prices in facilitated gas markets

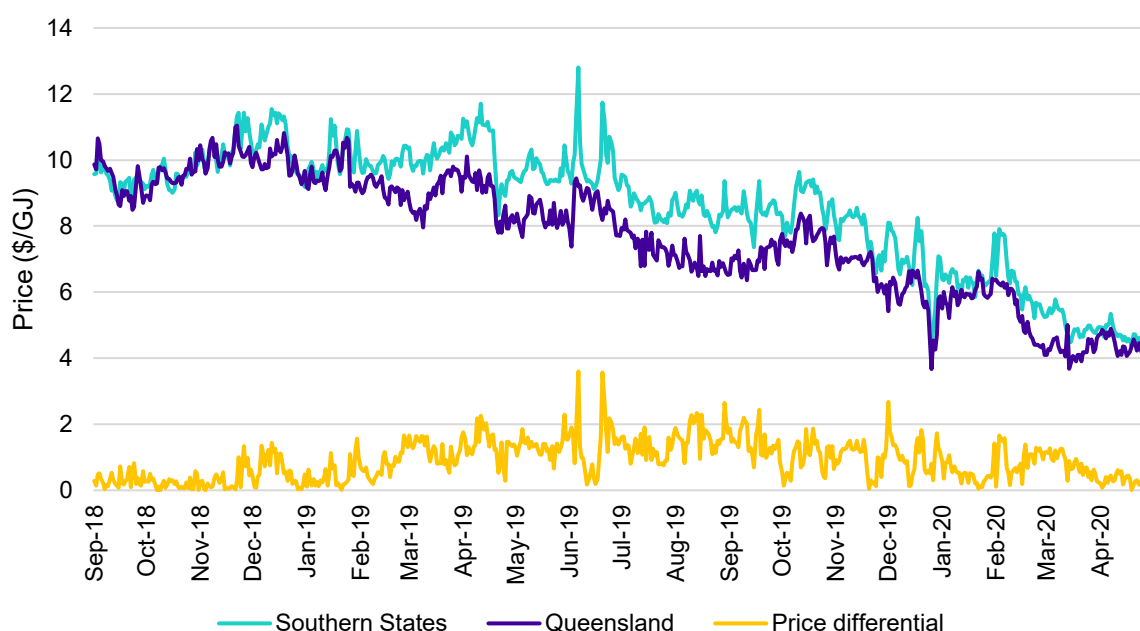
This section reports on prices and quantities of gas traded through the facilitated gas markets, as well as Victorian gas futures markets.

2.8.1. Prices paid in the facilitated gas markets have fallen significantly since September 2019

Chart 2.10 below shows daily average prices, and the difference between average prices, paid for gas in facilitated markets in Queensland and the southern states.

The average daily price in Queensland is calculated as the simple average of daily prices in the Wallumbilla Gas Supply Hub (GSH) and the Brisbane Short Term Trading Market (STTM), while average daily prices for the southern states are calculated as the simple average of daily prices in the Victorian Declared Wholesale Gas Market (DWGM) the Sydney and Adelaide STTM.

Chart 2.10: Daily prices paid in domestic facilitated gas markets



Source: ACCC analysis of data obtained from the Australian Energy Market Operator.

Chart 2.10 shows that prices in facilitated markets in both Queensland and southern states have declined further since the ACCC’s January 2020 report. With the exception of brief spikes in June and July 2019, prices in both markets decreased gradually throughout 2019. After a slight recovery in October 2019, average prices in Queensland and southern states fell from more than \$9/GJ to less than \$4/GJ in April.

While the ACCC’s January 2020 report noted an increasing gap between average prices in Queensland and the southern states over the first three quarters of 2019, this price differential has since narrowed and was less than \$1.50/GJ for most of early 2020. This likely reflects, at least in part, seasonal differences for demand in the southern states (with winter typically being a period of peak demand). By the end of April 2020, average prices in southern facilitated markets were roughly \$4.60/GJ, compared to \$4.30/GJ in Queensland.

Average prices in southern states declined significantly in Q1 2020 compared to Q1 2019, with the average price of \$5.89/GJ in Q1 2020 being about 40 per cent lower than that in Q1 2019 (which was \$10.07/GJ).

Prices also declined in Queensland over the same period. Simple average prices in Q1 2020 were \$5.17/GJ, compared to \$9.28/GJ in Q1 2019, a decrease of 44 per cent.

Prices in the facilitated markets have declined further than prices offered for 2020 and 2021 (discussed in section 2.4), as well as prices agreed to under recently executed GSAs (discussed in section 2.6).

The Australian Energy Regulator’s (AER) Wholesale Market Quarterly Report for Q1 2020¹²⁰ identifies a number of factors that may have contributed to the decline in prices in the facilitated markets over the past 12 to 16 months.

As noted in the AER’s report, and discussed further in section 2.5.1, increasing global LNG supply capacity and subdued demand over the second half of 2019 has placed downward pressure on international LNG spot prices. A contributing factor to subdued demand has

¹²⁰ Australian Energy Regulator—*Wholesale Markets Quarterly Q1 2020*.

been relatively mild winter weather in north Asia. More recently, the COVID-19 pandemic has further reduced global gas and LNG demand, placing further downward pressure on international LNG prices.

The Day Ahead Auction of contracted but un-nominated transportation capacity has also contributed to prices falling in the southern states and the reduction in the price differential between the north and the south, by enabling greater volumes of gas to be transported south from Queensland.

While prices have fallen, the quantity of gas exchanged through the facilitated markets in the southern states remained relatively unchanged, at least on an annual basis. In 2019, they grew by just 3 per cent, from 313.31 PJ in 2018 to 322.46 PJ. On a quarterly basis, the quantity of gas exchanged was marginally lower in the first quarter of 2020 (53.4 PJ) than it was in the first quarter of 2019 (54.3 PJ).

In contrast to the southern states, the quantity of gas exchanged in the facilitated markets in Queensland grew by 26 per cent in 2019, from 61.46 PJ to 48.64PJ. This increase was primarily driven by an increase in the volume traded through the Wallumbilla GSH. On a quarterly basis, however, the quantity exchanged in the first quarter of 2019 and 2020 were virtually the same (16.74 PJ in 2020 compared to 16.72 PJ in 2019).

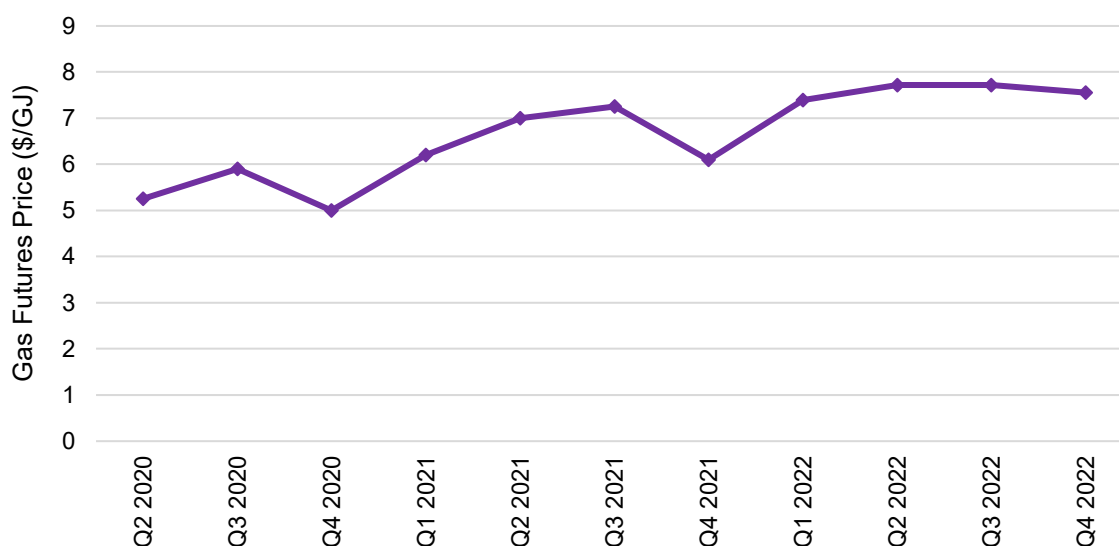
All other things equal, an increase in the liquidity of domestic facilitated gas markets would be a positive outcome for market participants.

2.8.2. Victorian gas wholesale futures trading

The Victorian DWGM allows market participants to trade natural gas futures contracts listed by the Australian Stock Exchange (ASX). Futures contracts reflect the collective expectations of market participants for gas prices in the DWGM in relevant quarters. They also provide a mechanism through which participants can hedge and manage their exposure to future gas price fluctuations.

Chart 2.11 presents prices for Victorian DWGM futures, and shows that market participants' expectations of gas prices over 2020, 2021 and 2022 have decreased significantly since the ACCC's January 2020 report. The January 2020 report noted that market participants expected gas prices to fluctuate between \$8/GJ and \$10/GJ over the next two years. Market expectations have since softened significantly, and participants now expect gas prices in the DWGM to remain between \$5/GJ and about \$7.80/GJ until the end of 2022.

Chart 2.11: Victorian DWGM futures prices from Q2 2020 to Q4 2022



Source: ACCC analysis of data obtained from the Australian Securities Exchange.

Table 2.11 presents monthly trading activity for Victorian gas futures. In the five months from November 2019 to March 2020, there were a total of 429 quarterly and 60 yearly futures contracts traded. This is a 10 per cent increase when compared to the equivalent prior year period from November 2018 to March 2019 (during which there were a total of 445 futures contracts traded).

The average number of futures contracts traded monthly on the DWGM from November 2019 to March 2020 also increased when compared to the corresponding prior year period, from 89 contracts per month to 98 contracts per month (a 10 per cent increase).

Table 2.11 Victorian DWGM futures trading activity over the period November 2019 to March 2020.

Month	Quarterly 2020	Quarterly 2021	Yearly 2021
November 2019	5	65	15
December 2019	15	120	30
January 2020	10	20	5
February 2020	75	20	0
March 2020	59	40	10

As at the beginning of June 2020, there were 641 quarterly outstanding futures contracts on the DWGM, covering an expiry period of Q2 2020 to Q4 2021. Notably, there were no outstanding contracts for 2022. This is an increase from our last report, where there were 525 contracts outstanding. The increase in both the average number of futures contracts traded, as well as the number of outstanding futures contracts on the DWGM, since our last report suggests that the DWGM futures market is becoming more liquid.

3. C&I user experience

3.1. Key Points

- Due to the disruptive impact of the COVID-19 pandemic on businesses, C&I users have had much lower engagement with the ACCC for this report than previously. The COVID-19 pandemic has brought opportunities for some C&I users, but has led to lower demand for other C&I users' products and increased the risks they face generally, as well as the risks posed by take or pay obligations.
- A number of C&I users have reported an easing of conditions in the gas market, with suppliers reportedly being more responsive to requests for offers and prices easing somewhat over the last six months.
- While conditions have improved to an extent, most C&I users view the improvements as temporary and believe that prices will rise again given the medium to longer-term demand-supply outlook is still expected to be quite tight. This has been reflected in the pricing of longer-term offers received by some C&I users.
- High gas prices therefore continue to be a key concern for C&I users, with a number repeating earlier concerns about the impact this could have on their business, investment and longer term viability of their operations.
- Concerns also continue to be raised about the lack of competition amongst producers and retailers, the imbalances in bargaining power and information asymmetries that C&I users face in negotiations and the impact of high take or pay obligations.

3.2. COVID-19, high gas prices, onerous contract terms and lack of competition among top concerns of C&I users

In March, the ACCC invited more than 40 large and small commercial and industrial (C&I) users to take part in a survey and bilateral meetings on their experiences in the gas market.¹²¹ These C&I users collectively account for about 35 per cent (90 PJ/a) of C&I demand in the east coast gas market and use gas:

- as a feedstock to produce fertilisers, explosives, chemicals, and plastics, or
- as a heat source for boilers and furnaces, for producing steam, or for drying processes.

Of the 40 C&I users that we approached, ten participated in the survey and eight participated in bilateral meetings. This is much lower than our usual response rate and reflects the disruptive effect of COVID-19 on many businesses. Nine of the users that responded were larger C&I users (i.e. those consuming more than 1 PJ per annum). As a result of limited engagement from small C&I gas users (usage under 1 PJ per annum) we are unable to make any observations about the experience of this group of C&I users. The inquiry has previously reported the different experiences of large and small C&I users.¹²²

We also sought further feedback on the impacts of COVID-19 on C&I gas users in May 2020.

All the C&I users that responded to the survey ranked gas prices as their most important concern in relation to their gas supply. Concerns were also raised about the availability of supply, the lack of competition among gas producers and retailers, and the uncertainty surrounding longer-term conditions in the gas market.

¹²¹ The ACCC has previously surveyed and conducted meetings with C&I gas users in: September and December 2017, July and September 2018, June and September 2019.

¹²² ACCC, *Gas inquiry 2017–2025 Interim report*, July 2019, p. 78.

Although concerns were raised about each of these matters, a number of users have reported an improvement in the responsiveness of suppliers to requests for offers and have also reported some reduction in prices since we last spoke to them. These users attributed the change in the suppliers' behaviour to the softening conditions in the LNG market. While this is a positive development, a number of C&I users noted the long-term demand-supply outlook in the east coast is still tight. With no clear signs that conditions will ease significantly, these users viewed the improvements as temporary.

Further detail on the feedback C&I users provided through the survey and bilateral discussions is provided below.

3.3. The impacts of COVID-19 on C&I users' demand and operations have varied markedly

The reported impacts of COVID-19 on C&I users to May 2020 have varied. A number of C&I users, for example, have redeployed their manufacturing operations to meet the additional demand for health supplies (e.g. hospital grade hand sanitiser).¹²³ Others have reported increased demand for their products (e.g. food processors and toilet paper manufacturers) in the early stages of the pandemic.

On the other hand, some C&I users reported that the demand for their products had fallen substantially, in some cases by more than 30 per cent. Some C&I users, who had previously reported significant concerns about the longer-term viability of their operations, noted that shutting their business temporarily may lead to permanent closure without additional government support.

In addition to these impacts, one C&I user noted that the impact of the COVID-19 pandemic had exposed potential supply chain vulnerabilities where they are reliant on importing key inputs to their processes. This manufacturer is the sole Australian producer of an essential product. Another C&I user reported delaying execution of a GSA due to economic uncertainty.

One C&I user reported they were already reducing production significantly saying:

'We are currently shutting down one of our machines for two weeks due to market demand dropping substantially'.

Another C&I user reported the fall in gas prices could lead to lower gas supply beyond 2023 saying:

'Change in demand as a result of COVID-19 has resulted in at best a delay and at worst cancellation of planned capital expenditures by upstream gas producers in maintenance and expansion of gas production. With the GSOO indicating tightness in the market in 2023 and beyond, we are concerned that the current environment can further exacerbate the situation if the planned and scheduled gas production does not ramp up'.

For further discussion on the long-term supply outlook, see section 1.3.

¹²³ See Chemistry Australia media release: <https://chemistryaustralia.org.au/news-events/australian-paint-manufacturers-ready-to-support-demand-for-hand-sanitiser>.

3.4. While conditions have eased recently, C&I users remain concerned about high gas prices and imbalances in bargaining power

Over the last six months, C&I users have reported improvements in both the prices offered by suppliers and their responsiveness to gas supply requests. A number of suppliers are reportedly more proactive and making unsolicited offers to C&I users, rather than C&I users having to 'chase' suppliers for offers. As one user noted:

'I have been doing this for ten years and this is the first time I've ever had a number of producers reach out to me individually and market gas other than through expressions of interest processes.'

The improvements reported by C&I users are consistent with what we have observed in the offers and GSA analysis set out in Chapter 2, with average prices offered to C&I users falling below \$9.50/GJ.¹²⁴

While prices have eased, C&I users noted that the prices they were offered had not fallen to the same extent as the facilitated gas market prices or the LNG netback prices (see Chapter 2). They also noted that the suppliers had not been as quick to respond to downward movements in the LNG netback price as they had been to upward movements.

As one user noted:

'Spot prices have reduced with more gas being diverted back into the domestic market. Recent oil price/LNG market changes have also suppressed prices however this hasn't directly flowed into contracted, firm supply agreements.'

Elaborating on this, a different C&I user noted that:

'Domestic gas buyers should not be exposed to a one sided international link. Currently buyers pay high prices if international LNG/oil prices rise but do not receive lower prices when those international prices decrease. The apparent domestic floor on forward gas prices, which prevents gas buyers from receiving lower international net back prices, shows there is insufficient market competition in the upstream gas market.'

As noted in Chapter 2, the disparity of domestic offers and contract prices from expected LNG netback prices is a concern that we intend to investigate further over the latter half of 2020.

Setting this aside, a number of C&I users noted that they did not expect the improved conditions to last very long, given that the longer-term demand-supply outlook in the east coast is still expected to be quite tight. One large C&I user said:

'There is still no certainty on gas prices on any horizon making business investment decisions difficult, particularly when our business is exploring growing its manufacturing asset base.'

Consistent with earlier survey responses, C&I users also expressed concerns about the effect that higher gas prices could have on investment in their businesses and the longer-term viability of operations, with one user noting that

¹²⁴ Pricing chapter 2.4.1.

'We work in cycles to refurbish and update machinery. Current gas prices are impacting forecasts of profitability making it extremely difficult to justify continued investment in our facility which is not a sustainable long term position.'

Concerns were also raised about the imbalance in bargaining power and information asymmetries faced by C&I users, with a number of C&I users claiming that:

- there was no effective negotiation of price or non-price terms and conditions with suppliers:

'There is no room to negotiate contracts. Or squeeze out costs. It's a case of take it or leave it.'

- the lack of transparency surrounding forward prices was making it difficult for C&I users to assess the reasonableness of the prices offered by suppliers:

'There are no long-term prices available—no proper price discovery of gas in two or three years'.

The imbalance in bargaining power and information asymmetries faced by C&I users have reportedly been exacerbated by the use of expression of interest (EOI) processes by some producers. According to C&I users, these EOI processes, which require interested buyers to submit bids in a blind auction-style process, have been 'completely opaque', with no information provided by the producers on the amount of gas being offered or the outcome of the process. Some also claimed that the EOI processes were being used by producers as a 'fishing expedition' to collect information on the maximum amount users were willing to pay for gas, rather than being used to allocate gas, with the information collected through this process then used to try and extract higher prices in bilateral negotiations.

3.5. Take or pay obligations are a heightened source of concern for C&I users with the advent of COVID-19

In our July 2019 report, we reported that non-price terms and conditions, in particular take or pay obligations, were a growing concern for C&I users.¹²⁵ In our January 2020 report we also noted that take or pay obligations in GSAs were continuing to increase.¹²⁶ The COVID-19 pandemic and shutdowns have increased C&I users' concern about these obligations.

C&I users raised concerns about the attempts by some incumbent retailers to try to discourage C&I users from switching to another supplier by offering to either forgive any financial obligation arising under the take or pay obligation, or to allow it to be repaid over the period of the new contract.

More generally, C&I users raised concerns about the inclusion of take or pay obligations in retail supply contracts. One user described the inclusion of these obligations in retail contracts as 'farcical' because:

- most C&I users that have gas delivered to their site by a retailer have no ability to sell or store gas, so they cannot effectively manage the risks associated with this obligation, and
- in contrast to C&I users, retailers are able to on-sell any gas not required by a user (or use the gas for electricity generation if they own GPG), and therefore recover some or all of the costs associated with this gas through other means.

¹²⁵ ACCC, *Gas inquiry 2017–2025 Interim report*, July 2019, pp. 81.

¹²⁶ ACCC, *Gas inquiry 2017–2025 Interim report*, January 2020, pp. 67–69.

Further, many C&I users reported that they are slowing production due to the COVID-19 pandemic which raises the potential for significant adverse consequences for these users in having to pay for gas that they cannot use or on-sell.

‘We have seen some reduction in production as a consequence of the closure of most restaurants and other food service outlets. This may require us to pay for non-used gas through our take or pay contract requirements which would be an unfortunate consequence when industries are under operational stress.’

One user reported not entering into a relatively low priced GSA due to the high take or pay obligation and their uncertainty about gas usage due to the COVID-19 pandemic.

In contrast to these concerns about take or pay obligations, one C&I user reported negotiating a take or pay obligation that requires it to pay the difference between the contract price and the average facilitated market price on any volumes that it does use (rather than having to pay the full contract price for all of these volumes). In effect, this provision, recognises that the supplier has the option to sell any gas that the C&I user does not take in the facilitated gas markets, and that to be in the same financial position, it only needs to be paid the difference between the facilitated market price and the contract price. This appears to be a good outcome that appropriately manages the risks faced by both suppliers and buyers and may indicate competitive pressure coming from a relatively new market entrant.

3.6. C&I users face challenges in using facilitated gas markets, but some retailers are starting to offer products that provide some exposure but also an ability to manage the risks

We have previously observed an increase in the number of C&I users looking to use the facilitated gas markets to minimise their costs in procuring gas.¹²⁷ These C&I users have, however, faced a number of challenges in using these markets. Some C&I users have, for example, reported that becoming a participant in the facilitated markets was unnecessarily complicated, time consuming, and resource intensive. One user also raised concerns about the difficulties negotiating access to the gas distribution networks in the STTM hubs.

‘Some gas distributors did not appear to understand that large gas consumers could become wholesale gas participants and would become their direct customer. In general, gas distributors were extremely slow to provide their regulated transportation agreement to allow us to execute. This process took nearly a year, with some distributors appearing to not provide an agreement until close to when our wholesale arrangements were to commence.’

Users also face costs and complexities associated with managing their day to day participation in the markets, which has led to a number of users outsourcing this function. There are, however, costs associated with this, which users note can vary markedly across providers of these services.

A further challenge faced by C&I users wanting to participate in the facilitated gas markets, or to have exposure to the prices in these markets, is being able to procure competitively priced hedging products, particularly in the STTMs. Currently there are ASX gas futures products available for the Victorian declared wholesale gas market and the Wallumbilla Gas Supply Hub, but not for the STTMs. The ASX is investigating introducing a product for the Sydney STTM.¹²⁸ Some retailers have responded innovatively to this gap in the market by offering C&I users facilitated market linked products with a price cap.¹²⁹ Apart from providing

¹²⁷ ACCC, *Gas inquiry 2017–2025 Interim report*, January 2020, pp. 78–80.

¹²⁸ AEMC, *2020 Gas markets liquidity review—Draft Report*, April 2020, p. 106.

¹²⁹ Such a product could, for example, require the buyer to pay the STTM price up to a cap of \$10/GJ. The cap in this example would provide the C&I user with protection against the price exceeding \$10/GJ.

C&I users with some protection against prices exceeding the price cap, this new type of product would allow those C&I users that want some exposure to the facilitated markets to avoid some of the complexities of directly participating in the markets themselves.

4. Transportation and storage

4.1. Key points

- The standing prices published by most pipeline operators increased in line with inflation between July 2019 and January 2020, as did the actual prices paid by shippers. By implication, this means that the monopoly pricing we first observed in our 2015 East Coast Gas Inquiry has continued. The key exceptions were the TGP, where the minimum price paid by shippers fell by 13 per cent and the two pipelines servicing South Australia, where the maximum prices paid by shippers on both the MAPS and PCA increased by 15 per cent.
- The price increases on the MAPS and PCA pipelines are on top of increases we reported in our July 2019 interim report. Prices on the PCA have risen by 61 per cent over July 2018 to January 2020, while the maximum price on the MAPS rose by 17 per cent over the same period. The level of these increases suggests that competition is not constraining the prices charged by the two pipelines.
- Between July 2019 and January 2020, the prices paid on the Dandenong storage facility increased in line with inflation, while the maximum price paid by users of the Iona storage facility increased by more than inflation.
- Our examination of negotiations for access to key pipelines highlights one of the risks in relying on more gas being able to flow from Queensland into the southern states; if a shipper or producer in the north is unable to obtain timely access to key pipelines and facilities in order to transport gas to the southern states, then the risk of a shortfall in the East Coast Gas Market is increased.
- Between March 2019 and February 2020, a large number of negotiations were undertaken between pipeline operators and shippers on key pipelines. In most cases, the negotiations were completed within two months, but there were a number of cases where negotiations took longer. This can reflect a range of factors, including whether there was any uncontracted capacity, the type of service sought by the shipper, and whether any capital works were required.
- There are signs that new contracts and variations may be moving to longer contract terms. Between 15 March 2019 and 24 February 2020 a total of 41 new GTAs and variations that included a firm forward haul service were executed. Of these, 13 were for terms of three years or more, and a further 19 were for terms of more than one year. While this is longer than the contract terms we observed the last time we examined this issue, it is considerably shorter than the 10 to 15 year terms that are usually required to underwrite a major expansion or development of a new pipeline.
- The Wallumbilla compression facilities are fully contracted, limiting access to capacity on the SWQP between Wallumbilla and Moomba. The southern haul capacity of the MAPS is also fully contracted over this period. This lack of uncontracted capacity could pose a problem in 2021 if producers in the southern states experience any delays or difficulties producing gas from undeveloped 2P reserves and more gas has to flow south.

4.2. Prices have increased on some key facilities in southern states

Over the course of the Inquiry the ACCC has reported on the prices paid for firm forward haul services by shippers (pipeline users). Using information provided by pipeline operators, this report updates this analysis to include the prices payable for firm forward haul services on major pipelines as at January 2020, as well as updated standing prices published by pipeline operators.

We have also updated the analysis to include the prices payable for use of the Dandenong LNG and Iona underground storage facilities. 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 prices.

Box 4.1: Approach to reporting prices

The prices reported in this section 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.

Method used to report pipeline prices

The prices for some firm forward haul services are recovered through a capacity charge only (i.e. \$/GJ of 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 per cent load factor (i.e. assuming the shipper uses all the capacity it has contracted).

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).

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 is measured on a dollars per GJ of storage capacity per day basis (\$/GJ/day). The variable charge, on the other hand, is measured on a dollar per GJ basis and 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 'new price' is used to refer to prices payable under contracts and variations negotiated since July 2019.

The term 'standing price' is used to refer to:

- the price pipeline operators subject to Part 23 of the NGR are required to publish as part of the standing terms for each service offered by the pipeline
- the prices pipelines subject to light regulation are required to publish for light regulation services
- the reference tariffs pipelines subject to full regulation are required to publish.

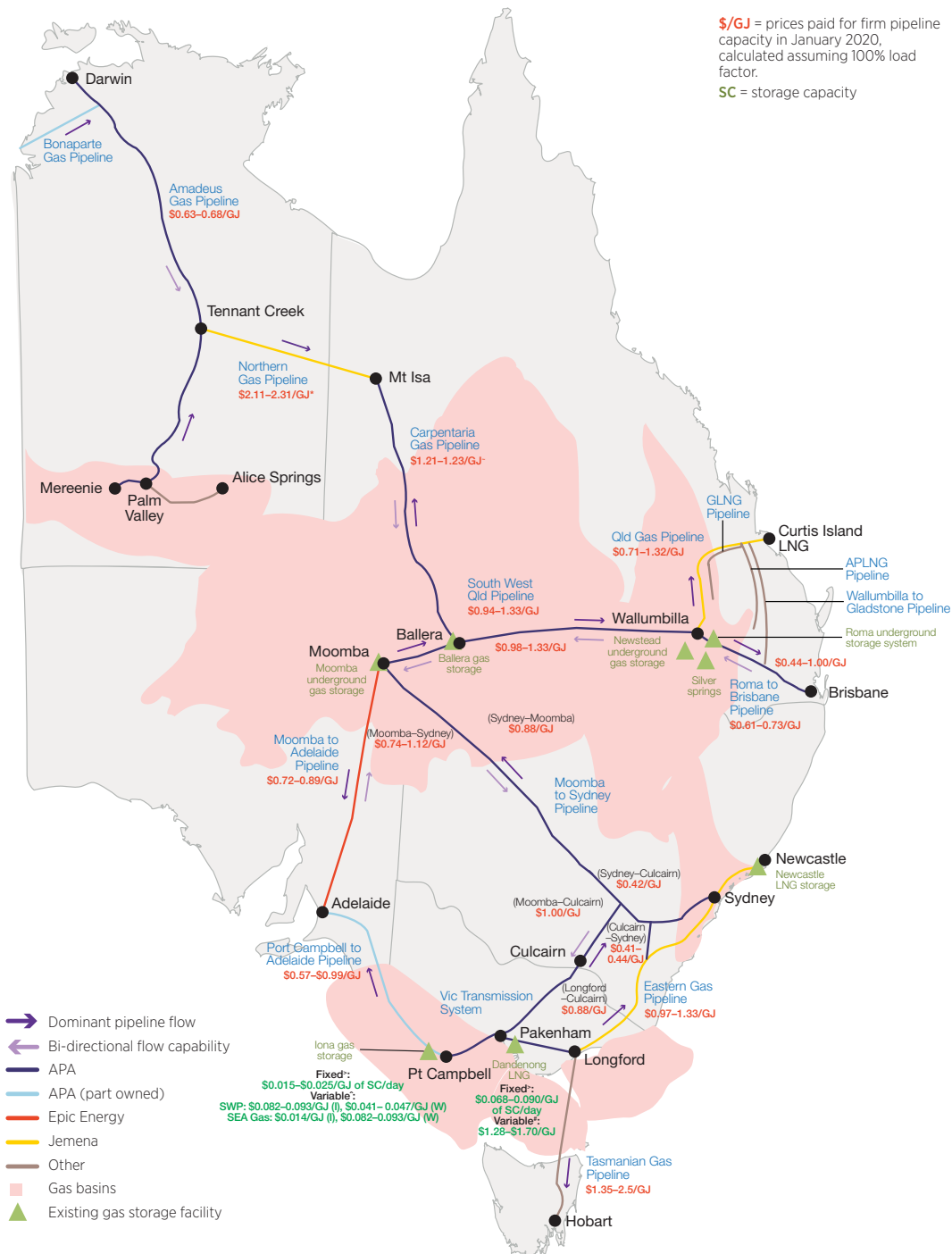
Comparability of prices

The prices payable by shippers for use of pipelines and storage facilities will reflect, amongst other things, the terms and conditions specified in their transportation and storage agreements and when the prices were agreed. The 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 and whether services are provided across a number of assets.

The map at figure 4.1 provides a snapshot of the minimum and maximum prices paid by shippers for firm transportation and storage services in January 2020. The prices paid for firm forward haul transportation on most pipelines has increased with CPI, in line with what we have observed on most pipelines over the past three and a half years. While this may not be particularly surprising given the lack of contracting activity on many pipelines, it is of some concern given the evidence of monopoly pricing that was found in the ACCC's 2015 Inquiry.¹³⁰

¹³⁰ ACCC, *East Coast Gas Inquiry 2015 final report*, April 2016, chapter 6. As noted in the 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.

Figure 4.1: Firm transportation and storage prices as at January 2020



Notes: The transportation and storage prices are based on invoices in January 2020 provided by operators, and exclude GST. Actual prices in transportation and storage agreements may vary due to differences in key commercial terms. For transportation this may reflect differences in load factor, capacity commitments, service flexibility, contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement) and whether services are provided across a number of pipelines. For storage this may also reflect differences in capacity commitments, storage, withdrawal and injection rates, service flexibility, contract length and the time at which the prices were agreed or reviewed.

- * 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.

4.2.1. Prices have increased on key pipelines servicing South Australia

Since our January 2020 Report, the prices paid by shippers for firm forward haul transportation on most pipelines have increased with inflation, with some important exceptions. Notably, the prices payable by some shippers on the two pipelines servicing South Australia prices have increased sharply. Prices have also increased on the Northern Gas Pipeline (NGP), while the minimum price on the Tasmanian Gas Pipeline (TGP) has fallen.

Chart 4.1 shows the minimum and maximum prices paid by shippers for firm forward haul services between July 2016 and January 2020 on key pipelines in Queensland, the Northern Territory (Northern Pipelines) and the southern states (Southern Pipelines). The chart also shows the prices that have been agreed to under new contracts and variations entered into since July 2019.

As this chart shows, the prices paid by shippers for firm forward haul transportation on the two pipelines servicing South Australia (the Moomba to Adelaide Pipeline System (MAPS) and the Port Campbell to Adelaide Pipeline (PCA)) have increased since our last report.

On the MAPS both the minimum and maximum prices have increased. The minimum price has increased by 6 per cent from \$0.68/GJ to \$0.72/GJ, while the maximum price has increased by 15 per cent from \$0.78/GJ to \$0.89/GJ. The new maximum price is now 10 per cent higher than the standing price. This premium above the standing price may reflect the higher level of hourly flexibility in this contract relative to the hourly flexibility provided in the MAPS standard terms for firm forward haul services.

The maximum price payable on the PCA pipeline has also increased by 15 per cent from \$0.86/GJ to \$0.99/GJ. The new maximum price, which is 8 per cent higher than the standing price, was agreed through a variation to an existing contract, which resulted in the MDQ being reduced but the fixed monthly charge not falling by the same proportion.

This is the second year that we have reported on material price increases on the two pipelines servicing South Australia, with the PCA maximum price increasing by 61 per cent between July 2018 and January 2020 (from \$0.61/GJ to \$0.99/GJ) and the MAPS maximum price increasing by 17 per cent (from \$0.76/GJ to \$0.89/GJ) over the same period.

The magnitude of these price increases is concerning and indicates that competition between these two separately owned pipelines is having little or no influence on the prices charged by Epic and SEA Gas. This observation is consistent with our finding in the 2015 Inquiry that competition between two pipelines supplying gas from different fields to the same destination was not posing an effective constraint on prices charged by pipeline operators.¹³¹ It is also consistent with our observations in both our July 2019 review of the information published by the two pipeline operators under Part 23 of the NGR¹³², and our January 2020 review of the prices charged by the two for capacity trading and the day-ahead auction of contracted but un-nominated capacity (DAA).¹³³

It could be argued that the lack of competition between the two pipelines is not a structural problem but rather reflects the fact that the MAPS is fully contracted (see section 4.5). However, it is important to recognise that even if the MAPS had unused capacity, competition is unlikely to pose an effective constraint on the behaviour of the two because they do not compete directly to supply from the same locations. Rather, they compete

¹³¹ ACCC, *East Coast Gas Inquiry 2015 final report*, April 2016, section 6.2.2.

¹³² ACCC, *Gas inquiry 2017–2020 interim report*, July 2019, chapter 6.

¹³³ ACCC, *Gas inquiry 2017–2025 interim report*, January 2019, section 4.4.

indirectly to transport gas to Adelaide, via Moomba in the case of the MAPS and Port Campbell in the case of the PCA pipeline.

The price increases on the MAPS are particularly concerning given the likely flow on impacts on competition in the wholesale market. Price increases on pipelines that are able to deliver gas from Queensland to the southern states, such as the MAPS, raise the level of the buyer alternative and as result may increase prices in the wholesale market. There may also be flow on impacts from the lack of available capacity on MAPS (see section 4.5) for buyers seeking to purchase gas from southern producers or retailers, as the buyer alternative may not place an effective constraint on negotiations.

In addition to the price increases observed in South Australia, the minimum price on the NGP has also increased by 23 per cent from \$1.71/GJ to \$2.11/GJ. This increase stems from the expiration of a contract that provided for transportation services at a discount to the standing price. While the new minimum price is \$0.40/GJ higher, it is still \$0.20/GJ lower than the NGP standing price of \$2.31/GJ.

Price changes on the TGP have been mixed. A price has been agreed with a new shipper that is above the standing price, for a relatively small amount of capacity. However, the minimum price has fallen by 13 per cent from \$1.55/GJ to \$1.35/GJ as a result of a variation to an existing contract where the shipper has exercised an option to extend the contract at the rate agreed when the contract was originally entered into. This reduction in the minimum price follows other significant reductions obtained by shippers under new contracts and variations on the TGP following the arbitration completed in April 2018 under Part 23 of the NGR.¹³⁴

Chart 4.1 also shows the standing prices offered by most pipelines, which have largely continued to increase in line with inflation.

While not shown on this chart, APA continues to publish a higher standing price for the Roma to Brisbane Pipeline (RBP) on its website than the reference tariff approved by the AER, as first reported in our previous interim report.¹³⁵ The published tariff is now 9 per cent higher than the reference tariff (\$0.735/GJ versus \$0.674/GJ). When previously asked about this difference, APA informed the ACCC that the reference service is subject to the terms of the AER approved access arrangement, which includes provisions that differ from APA's standard gas transportation agreement (GTA) that applies to its published tariffs. APA, for example, noted the access arrangement includes annual tariff adjustments to reflect changes in inflation and the cost of debt, and rebates from the sale of rebateable services, while the standard GTA only provides for tariffs to reflect changes in inflation.

Notably, none of the reasons that APA cited reflected differences in the actual service or quality of service. Rather, they relate to factors that have resulted in the reference tariff falling over the period, including as a result of the revenue that APA has earned from the provision of rebateable services, 70 per cent of which is supposed to be passed back through to shippers in the form of lower reference tariffs.¹³⁶ APA's decision not to pass this benefit through to its published tariff is concerning as it has the potential to confuse prospective shippers on the pipeline and appears at odds with the intention of full regulation.

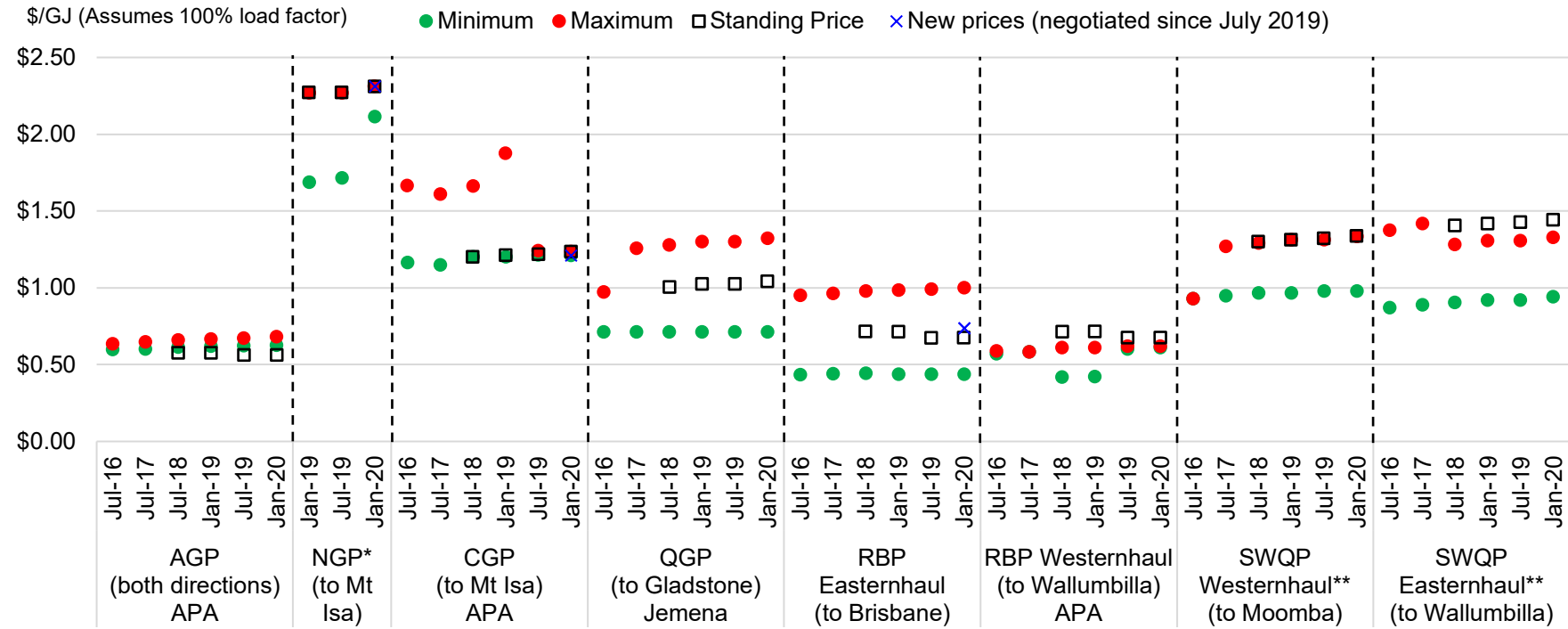
¹³⁴ ACCC, *Gas Inquiry 2017–2020 interim report*, December 2018, p. 101.

¹³⁵ ACCC, *Gas inquiry 2017–2025 interim report*, January 2020, pp. 87–88.

¹³⁶ AER, *Roma to Brisbane Gas Pipeline Access Arrangement 2017–22, Attachment 1—Services covered by the access arrangement*, November 2017.

Chart 4.1: Firm forward haul transportation prices (nominal)

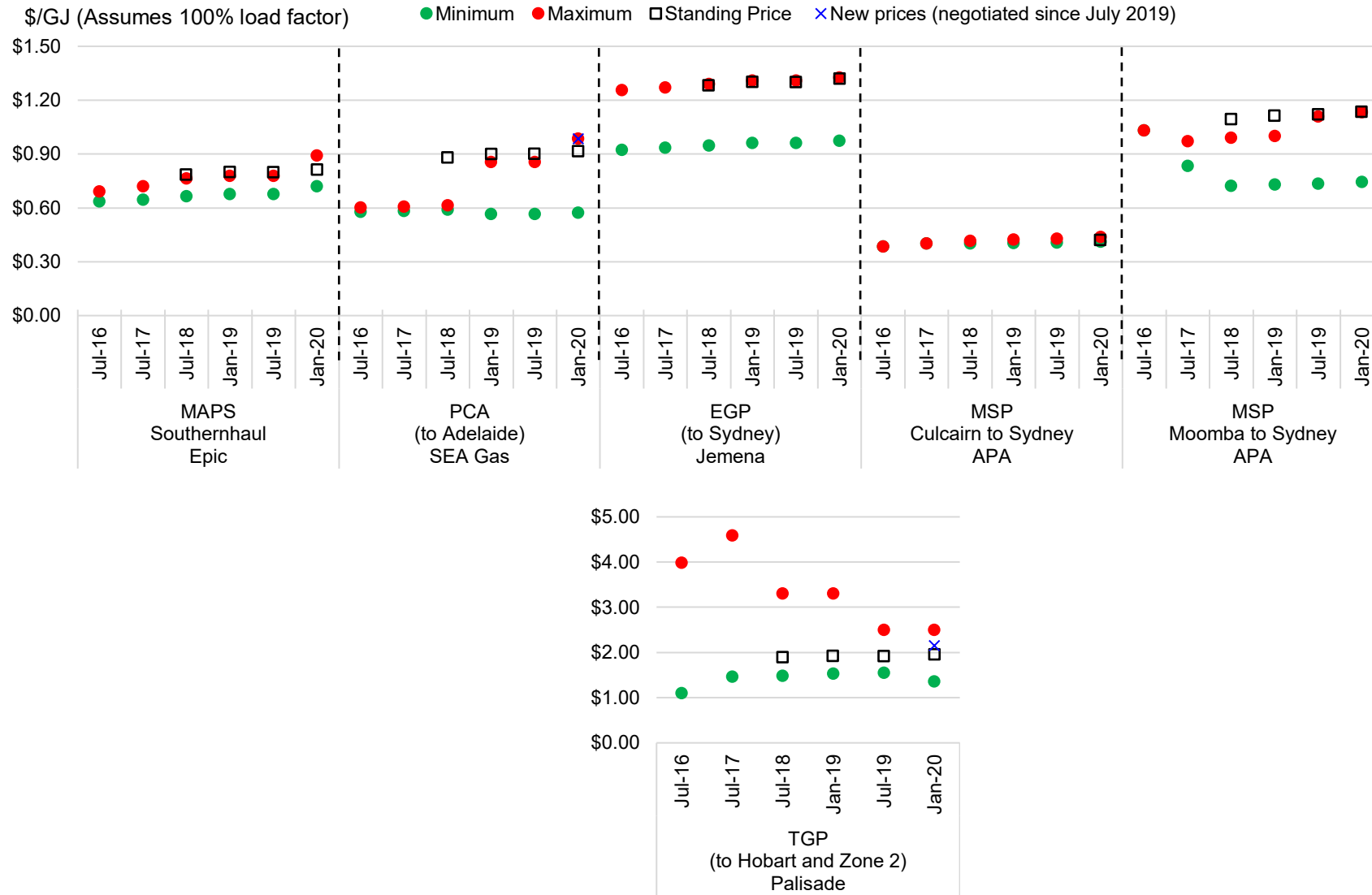
Northern Pipelines



* Includes the cost of the mandatory nitrogen extraction service

** Includes compression costs

Southern Pipelines



* TGP pricing changed from a distance based tariff to a zonal tariff as at 1 January 2018.

4.2.2. Storage prices have increased since our last report with prices paid for Iona Storage increasing beyond inflation

The Dandenong LNG and Iona underground storage facilities are the only facilities that provide storage services to third parties in the East Coast Gas Market. We previously reported the prices paid for storage services in these facilities for July 2018 and July 2019 in our December 2018 and January 2020 interim reports. The map at figure 4.1 extends this analysis by setting out the prices payable for these services in January 2020.

Table 4.1 shows the prices paid for storage at the Dandenong LNG storage facility are significantly higher than at the Iona underground storage facility. This reflects the different costs associated with the provision of storage by these two facilities. The Dandenong LNG storage facility is used to store small amounts of gas to be injected quickly into the Victorian Transmission System (VTS) to address short-term peaks and system security issues in Victoria. In contrast, the Iona underground storage facility tends to be used to store large amounts of gas during the summer months, which can then be withdrawn in winter to meet peak demand.

Table 4.1: Storage prices

	July 2019 (\$/GJ)	January 2020 (\$/GJ)
Iona Gas Storage		
Fixed	0.010–0.027	0.015–0.025
Variable–SWP	0.082 (I)–0.041 (W)	0.082 – 0.093 (I), 0.041–0.047 (W)
Variable–SEA Gas	0.014 (I)–0.082 (W)	0.014 (I), 0.082–0.093 (W)
Dandenong Gas Storage		
Fixed	0.067–0.089	0.068–0.090
Variable	1.26–1.70	1.28–1.70

Since July 2019, the spread of prices for the fixed charge at the Iona underground storage facility has contracted from \$0.010–\$0.027/GJ to \$0.015–\$0.025/GJ of storage capacity per day. This represents a 44 per cent increase in the minimum price and a 7 per cent fall in the maximum price paid.

There has also been an increase in the variable charges payable for injections into and withdrawals from the Iona underground storage facility as a result of a shipper entering into a new Gas Storage Service Agreement (GSSA). In contrast to the Iona underground storage facility, the fixed and variable storage prices at APA’s Dandenong LNG facility have increased in line with inflation, even with shippers entering into new GSSAs.

These price increases on the Iona underground storage facility have the potential to affect wholesale prices in southern states as Iona provides customers with the ability to purchase and store gas during periods of low demand (typically during summer) and withdraw it during periods of peak demand (typically during winter). As a result the Iona underground storage facility provides gas users with an alternative to purchasing gas for immediate use during periods of peak demand when prices are high.

Unlike pipeline operators, storage providers are not currently required to publish a standing price for storage services. As we noted in our joint ACCC-GMRG recommendations on measures to improve the transparency of the gas market¹³⁷, the absence of this information may make it difficult for prospective users of these facilities to determine whether to seek access and, if they do, to assess the reasonableness of the prices offered. We therefore recommended that storage providers be required to report the standing prices (including the standard terms and conditions) for their services and information on the prices actually paid by users of these facilities. This recommendation was considered by the COAG Energy Council through its Transparency Regulation Impact Statement (Transparency RIS) and has been accepted. We understand that the legal framework required to give effect to this recommendation is currently being drafted and that the reporting obligation is expected to be implemented in 2021.¹³⁸

4.3. Negotiating pipeline access can be a lengthy process

Continuing the analysis from our July 2019 report¹³⁹, the ACCC has reviewed information on shippers' access requests and pipeline operators' offers over the period 15 March 2019 to 24 February 2020. In carrying out this review, the ACCC has focused on:

- the time taken to negotiate new GTAs or variations to existing GTAs and the matters considered in those negotiations
- the outcomes of access requests made by shippers.

Our analysis has shown that contractual congestion is impacting a number of pipelines which are required to transport gas south from Queensland. While there are alternatives to firm transportation services, such as as available services, these come with increased risks for shippers. Negotiating the extensions or expansions for that would allow access to these contractually congested pipelines is likely to take longer than the one to two months observed for most negotiations. Finally, while the length of contract terms have increased since we last reported, they are generally still not long enough to underwrite significant expansions of capacity.

4.3.1. Negotiation timeframes vary for a variety of reasons

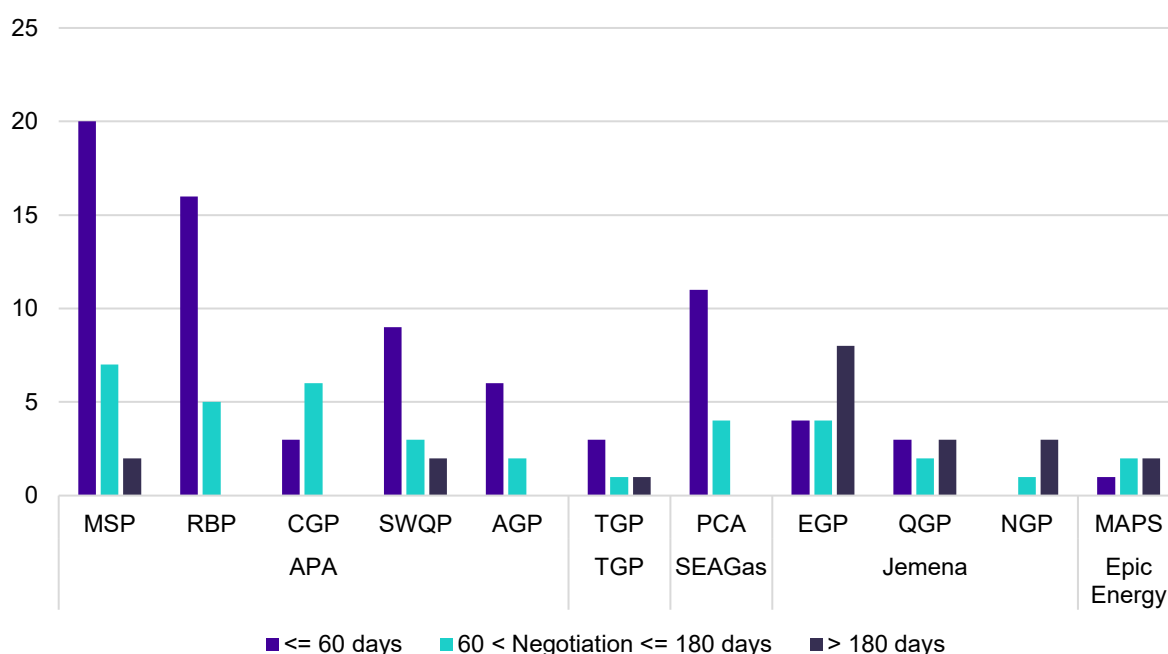
Chart 4.2 shows the number of negotiations that occurred on each pipeline between 15 March 2019 and 24 February 2020, broken down by negotiation length (i.e. less than 60 days, 60–180 days and greater than 180 days). Note that the number of negotiations reflected in this chart includes all the negotiations that occurred, including those that did not result in a new GTA or variation to an existing GTA.

¹³⁷ ACCC and GMRG, Joint recommendations: Measures to improve the transparency of the gas market, December 2018, p. 35.

¹³⁸ COAG Energy Council, Measures to Improve Transparency in the Gas Market Decision RIS, March 2020, p. xxix.

¹³⁹ ACCC, Gas Inquiry 2017–2020 Interim Report, July 2019, p. 156.

Chart 4.2: Negotiation lengths by pipeline



Note: The ACCC has defined the length of a negotiation as the time from when the first offer/request was received until either a GTA or variation was executed, or the last communication was made as part of the negotiation (where the negotiation is still ongoing or did not result in a new GTA or variation). Negotiations that have lapsed and which also lasted less than one week have been excluded.

Our July 2019 report found that negotiations between pipeline operators and shippers generally took around 1–2 months, with contract variations and extensions generally taking less than a month to negotiate, whereas new contracts took longer.¹⁴⁰ As chart 4.2 shows, while many negotiations are still concluded in less than 2 months, there is significant variation in negotiation lengths, with some negotiations requiring a significantly longer period of time than others. There were, for example, 21 negotiations that exceeded 180 days, with one of those negotiations taking over 500 days.

Lengthy negotiations are not, in and of themselves, an indication of a problem, because there are a number of legitimate reasons why negotiations may take some time to conclude. However if the time required to access key pipelines used for transporting gas south becomes extended, the risks to supply in southern states may be increased. Most of the lengthy negotiations, for example, tended to result from either:

- a lack of time pressure on the part of the shipper, or
- significant discussions over technical or legal requirements.

The former can occur where a shipper and pipeline operator are looking to extend a GTA on similar terms. Discussions of this nature may start some time before the existing GTA is due to expire, and with a lack of time pressure can take some time before the parties actually execute the new GTA. There may also be a lack of urgency in negotiations where the prospective shipper is developing a new industrial facility or gas field. These type of projects can take some years to develop, and so negotiations for transportation may begin a long time before transportation is due to commence.

Discussions over technical and legal requirements can arise where a shipper and pipeline operator may not have worked together before. This can lead to significant back-and-forth between legal departments as terms are agreed. It may also occur where the user has

¹⁴⁰ ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, p. 156.

specific technical requirements for its transportation service, or requires the use of multiple pipelines.

Other potential factors influencing negotiation time frames include:

- the extent to which the pipeline has any uncontracted capacity (see section 4.5)
- whether the pipeline operator needs to undertake any capital works to accommodate the shipper's requirements (e.g. construction of an extension, expansion or connection point)
- the type of contract being negotiated (i.e. an entirely new GTA versus a variation to an existing agreement) and whether the shipper is a pre-existing user of the pipeline
- the type of service(s) required by the shipper (e.g. firm transportation services, as available/interruptible transportation services, or ancillary services, such as capacity trading services) and the period over which they require the service
- the number of pipelines the shipper needs to use in those cases where a pipeline operator offers multi-asset contracts
- how streamlined the pipeline operator's processes are, with companies that experience more negotiations appearing to have more streamlined processes (e.g. standardised contracts) that allow for faster negotiations
- whether, in the case of pipelines subject to Part 23 of the NGR, the shipper is making a preliminary enquiry or a formal access request under the National Gas Rules.

Regarding this last factor, the ACCC has found previously that shipper requests are often treated as 'preliminary enquiries' rather than formal access requests.¹⁴¹ Based on our review of recent access requests, this would appear to still be the case. As noted in our July 2019 report, our key concern with the use of preliminary enquiries is that it may allow pipeline operators to avoid some of the requirements in Part 23 relating to access requests and negotiations, including response times. It can also slow a shipper's access to arbitration if negotiations fail, because to proceed to arbitration a shipper must submit a formal access request and go through the access offer and negotiation steps in Part 23.¹⁴²

To address this concern, the ACCC recommended in its July 2019 report that the distinction between preliminary enquiries and formal access requests in Part 23 be removed. We understand that this recommendation is currently being considered as part of the COAG Energy Council's pipeline RIS.

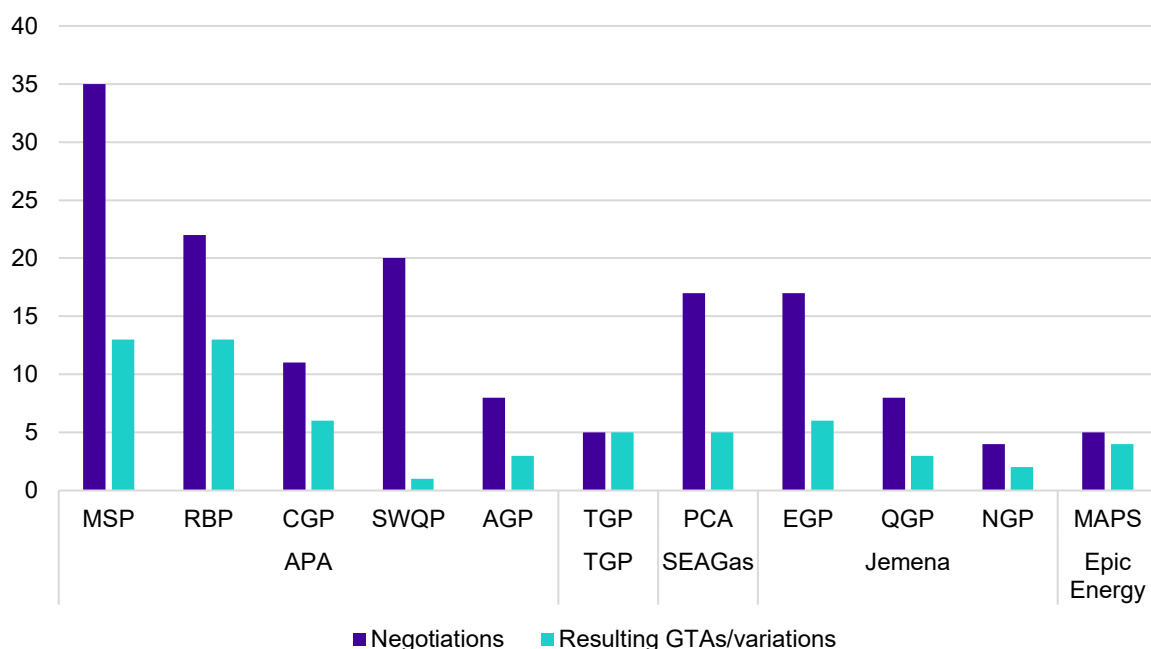
4.3.2. Outcomes of negotiations

Chart 4.3 below shows the number of negotiations on each pipeline and the number of new GTAs and GTA variations that resulted from these negotiations. It is worth noting that some of the access requests in the chart were still being negotiated at the time this data was provided by pipeline operators. Some of the difference between the number of access requests and new GTAs and variations can therefore be attributed to this factor.

¹⁴¹ ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, p. 156.

¹⁴² *Ibid.*

Chart 4.3: Number of negotiations resulting in GTAs or GTA variations



Note: Some of the negotiations in the chart had not concluded at the time this data was provided by pipeline operators. Some of the difference between the number of negotiations and new GTAs and variations can be attributed to this.

The chart shows that the number of negotiations that did not result in an executed GTA or variation in the period varied widely between pipelines. For example, all of the negotiations initiated on the TGP in the period resulted in new GTAs or variations in the period, whereas a large number of requests to access the Moomba to Sydney Pipeline (MSP) and SWQP did not.

The most common reason for a negotiation failing to lead to a GTA or variation is that the shipper breaks off the negotiation, or allows an offer from the pipeline operator to lapse. Based on our review of the material provided by pipeline operators, it would appear that this often occurs where a shipper makes an initial approach to a pipeline operator, seeking information on prices and/or the availability of capacity on a pipeline, and after receiving a response from the pipeline operator, decides not to proceed.

This is particularly the case on the SWQP for transportation between Wallumbilla and Moomba, access to which requires access to the Wallumbilla compression facilities which are contractually congested (see chart 4.5). The SWQP has had numerous initial requests from shippers, with the majority of these potential negotiations being abandoned by the shipper at an early stage. Many of these lapsed enquiries were for transportation services on other pipelines in combination with the SWQP.

The ACCC's analysis of access request and offer information provided by pipeline operators has indicated that, despite contractual congestion, there has been little recent evidence of discussions with shippers about capital expenditure to increase capacity on the SWQP or MAPS. As discussed in section 4.5, pipeline contractual congestion presents a risk to gas supply in the southern states from 2021 onwards. That said, following the release of the 2020 GSOO APA reiterated that it had investigated options to expand key pipelines through additional compression and could, if required by the market, provide approximately:

- 200 TJ per day of additional western haul capacity on the SWQP
- 225 TJ per day of additional southernhaul capacity to Sydney on the MSP, and

- 200 TJ per day of additional southernhaul capacity to Sydney on the MSP.¹⁴³

If an investment were to proceed, APA expect that this additional capacity could be available 18 months after a final investment decision. Given the importance of additional transportation capacity in allowing additional gas to flow south from Queensland, the ACCC will continue to monitor the progress of any proposed investments in transportation and storage capacity.

4.4. Contract terms appear to be increasing

In our July 2019 interim report, the ACCC reported on the number of new GTAs and variations that had been entered into on the following pipelines in the East Coast Gas Market between 1 August 2017 and 15 March 2019:

- the MSP, SWQP, Amadeus Gas Pipeline (AGP), RBP and Carpentaria Gas Pipeline (CGP) owned by APA
- the MAPS and South East Pipeline System (SEPS) owned by Epic Energy
- the Eastern Gas Pipeline (EGP), Queensland Gas Pipeline (QGP) and NGP owned by Jemena
- the PCA and Port Campbell to Iona Pipeline (PCI) owned by SEA Gas, and
- the TGP owned by Palisade.¹⁴⁴

We have updated this analysis to reflect the new GTAs and variations entered into between 15 March 2019 and 24 February 2020. During this period, a total of 43 new GTAs were entered into and 105 variations to existing GTAs were executed. Of the 105 variations, 18 resulted in a change to the price payable by the shipper for existing services or new services and 28 resulted in the provision of a new service. The remaining variations involved changes to other aspects of existing GTAs, such as receipt and delivery points, contract volumes and contract duration.

Of the 18 variations that resulted in new prices, 12 related to the provision of firm forward haul services (including five variations relating to changes in minimum monthly payments). The remainder related to the provision of other services including as available/interruptible transportation, park and loan services, and capacity trading services.

Chart 4.4 shows the number of GTAs and price variations for firm forward haul services by contract term length. There are a number of older long-term contracts that are not captured in this chart because they were entered into prior to 15 March 2019. The chart therefore does not represent all of the GTAs that are currently in force.

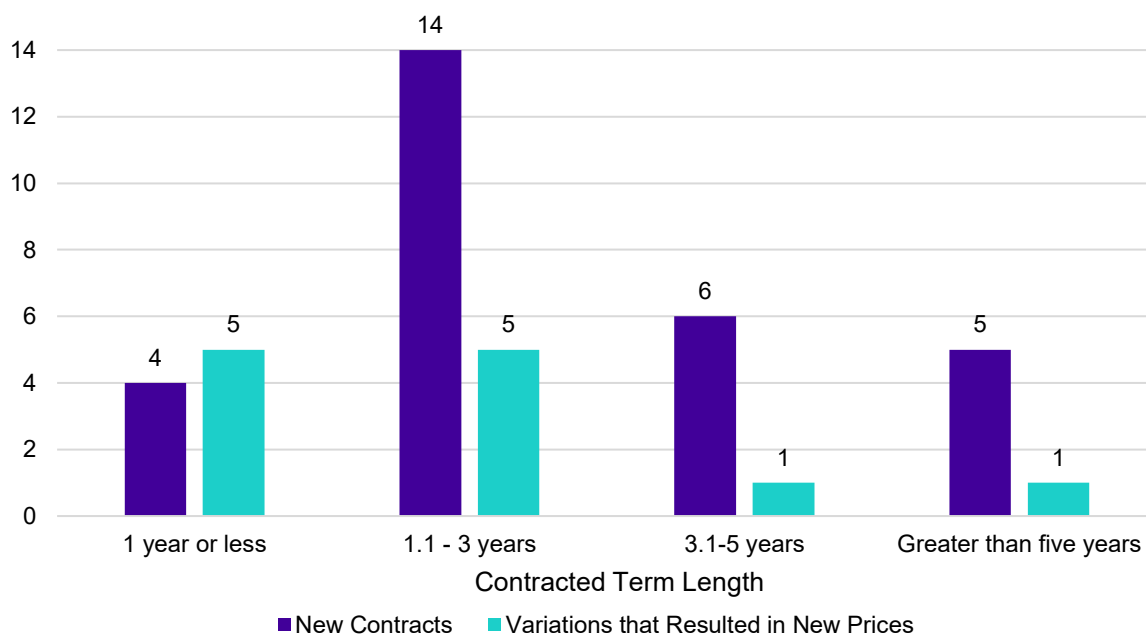
As shown in chart 4.4, just under half of the 41 new GTAs and price variations relating to firm forward haul services that were entered into over the period have a contract term of over one to three years. There were also a reasonable number of new GTAs and price variations that had a contract term of over three to five years (7 contracts) and greater than five years (6 contracts). This is in contrast to our prior review of contracts entered into between 1 August 2017 and 30 August 2018, which found that the majority of the new GTAs and variations had a contract term of one year or less and that only one GTA had a term greater than five years.¹⁴⁵

¹⁴³ APA, APA response to 2020 GSOO, 18 May 2020, <https://www.apa.com.au/news/media-statements/2020/apa-response-to-2020-gsoo/>.

¹⁴⁴ ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, p. 114.

¹⁴⁵ *Ibid.*, p. 115.

Chart 4.4: Contract terms for new GTAs and price variations relating to firm forward haul services



4.5. Most southern haul capacity is close to fully contracted

Chart 4.5 shows the contracted capacity outlook for the major transmission pipelines in the East Coast Gas Market between 1 May 2020 and 31 December 2021.

As this chart shows, the PCA pipeline, MAPS (northern haul), EGP, MSP, SWQP (eastern haul), AGP and NGP have a reasonable amount of uncontracted capacity available. There are, however, a number of other facilities where the capacity has been fully contracted, or close to fully contracted. This includes a number of facilities that are used to transport gas south from Queensland, which could pose a problem in 2021 if producers in the southern states experience any delays or difficulties producing gas from undeveloped 2P reserves and more gas has to flow south (see section 1.5).

The Wallumbilla compression facilities, for example, which are required to move gas from most points in Wallumbilla onto the SWQP¹⁴⁶, are fully contracted over this period. This limits access to capacity on the SWQP between Wallumbilla and Moomba. The southern haul capacity of the MAPS is also fully contracted over this period.

Shippers that do not currently have firm capacity on these facilities could therefore find it quite challenging to bring any additional gas from Queensland to the southern states over the next 18 months unless they are prepared to:

- enter into gas swaps with other suppliers, noting that there are limits on how much gas can be swapped between locations
- enter into secondary capacity trades with other shippers that have firm capacity on the relevant facilities
- rely on as available or interruptible services, which are lower in priority and typically more expensive than firm services

¹⁴⁶ These compression services are, for example, required to move gas from the Bewyndale to Wallumbilla Pipeline receipt point, the RBP receipt point, the Spring Gully Pipeline receipt point, the Darling Downs Pipeline receipt point and Wallumbilla low pressure trade point. See APA SWQP Tariff Matrix, https://www.apa.com.au/globalassets/documents/info/tariff-docs/swqp_tariffs.pdf

- use the DAA, which also has a lower priority than firm services.

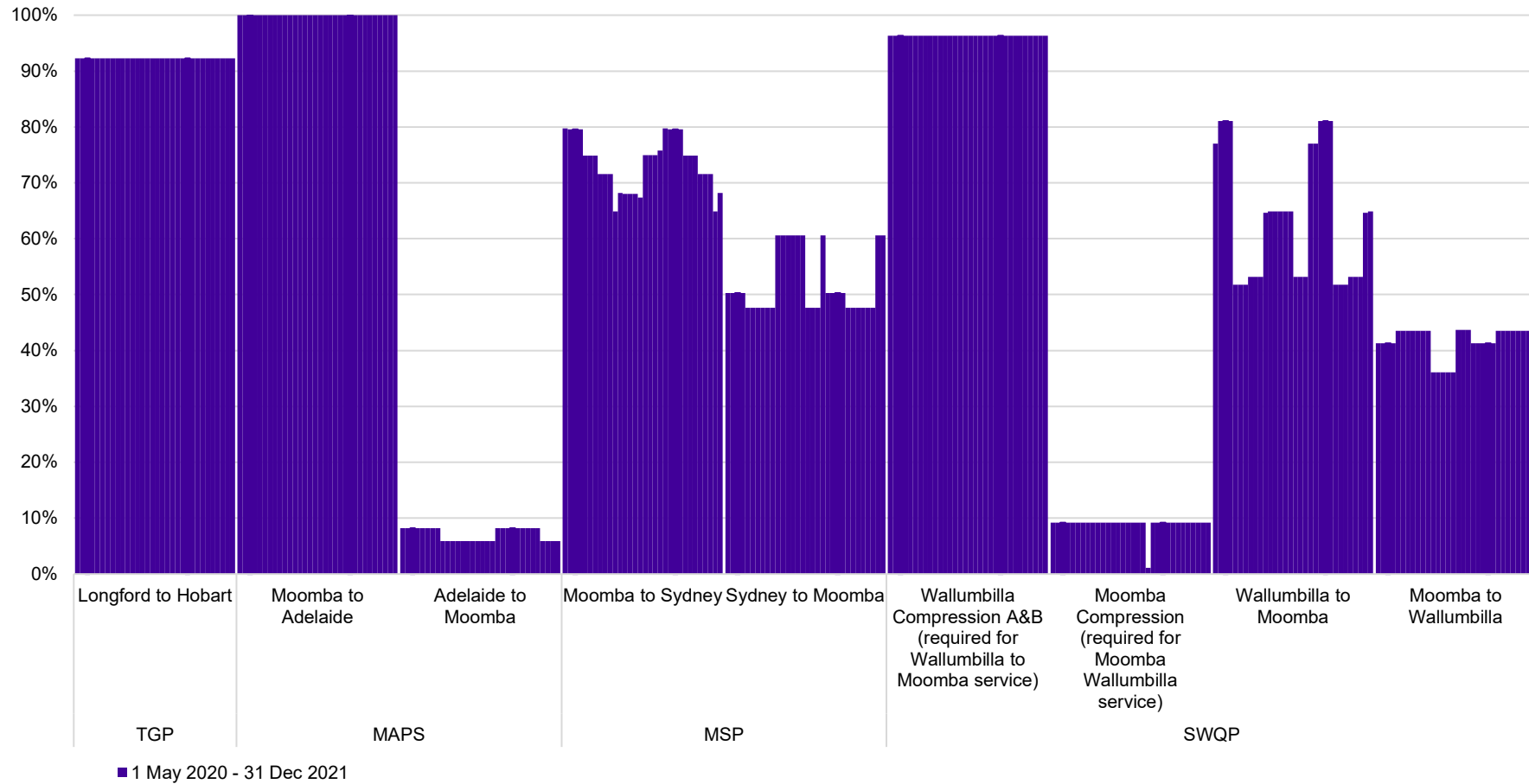
In relation to the DAA, it is worth noting that while this relatively new market mechanism has been used to successfully transport a significant volume of gas from Queensland south at a relatively low cost¹⁴⁷, the pricing and deliverability risks associated with the DAA may not be acceptable to many gas users. Specifically, as shown in the following section, some of the pipelines used to transport gas south are beginning to approach, or have already experienced, physical constraints during peak periods. This introduces a greater level of risk to those seeking to rely on the DAA that their capacity may be interrupted on the day. The same risk would also apply to those shippers seeking to rely on as available or interruptible services offered by pipeline operators. Consequently, it also increases the risk that a shortfall in supply may occur in the southern states in 2021.

¹⁴⁷ AER, *Wholesale Markets Quarterly—Q1 2020*, May 2020, pp. 50–51

Chart 4.5: Pipeline capacity between 1 May 2020 – 31 December 2021

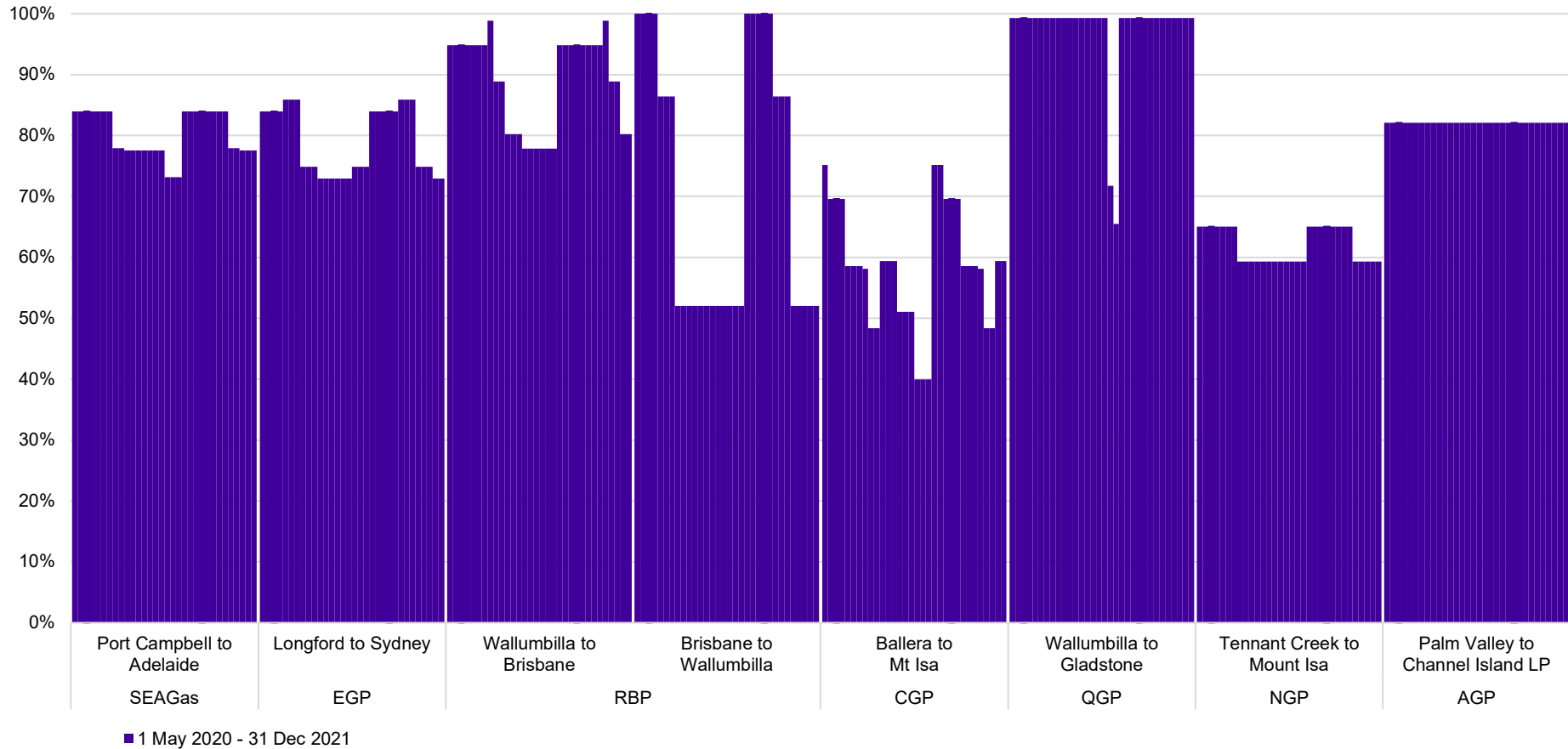
Southern haul pipelines

Proportion of Pipeline Capacity Contracted on Firm Basis



Other pipelines

Proportion of Pipeline Capacity Contracted on Firm Basis

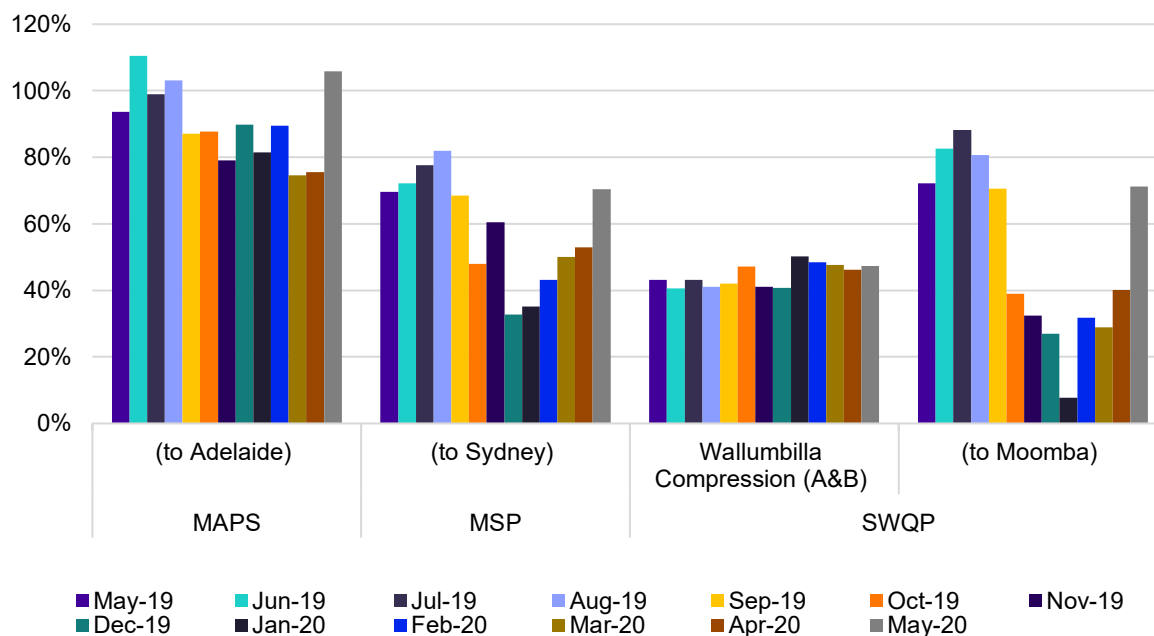


Sources: For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator's website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed 3 June 2020). For other 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 12-month uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed 11 May 2020).

To better understand the extent to which shippers that do not have firm capacity on the Wallumbilla compression facilities, the SWQP, MAPS and MSP are likely to experience difficulties transporting gas south using the DAA, or as available or interruptible services, we have examined the use of these facilities over the last year.

The results of this examination are summarised in chart 4.6, with the monthly utilisation measure in this chart representing the maximum physical gas flows in each month for the period May 2019–May 2020, expressed as a percentage of the facility’s nameplate capacity.

Chart 4.6: Maximum daily use by month expressed as percentage of nameplate capacity between May 2019 and May 2020



Sources: Actual pipeline flow and nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed 11 May 2020).

As this chart shows, the Wallumbilla compression facility, SWQP and MSP did not experience any physical constraints over the last year, although there have been some days in winter where utilisation of the SWQP has exceeded 80 per cent. In contrast to these facilities, the utilisation of the MAPS in most months exceeded 80 per cent and in some months exceeded 100 per cent. Shippers seeking to rely on the DAA or as available/interruptible services to transport gas south are therefore likely to experience greater risks of interruption on the MAPS than on other facilities.

Finally, it is worth noting that in those instances on the MAPS where utilisation has exceeded 100 per cent, Epic has been able to increase nameplate capacity in the short term to meet peak demand. This is not, however, a long-term solution. MAPS is therefore likely to require an expansion in the short- to medium-term. The SWQP is also likely to require an expansion in the medium term, given the relatively high utilisation of this pipeline in the winter months.

A: The ACCC's approach to reporting on prices offered in the East Coast Gas Market

This appendix sets out the ACCC's approach to the price reporting presented in chapter 2 of this report.

A.1 Parameters of reported prices

Unless specified otherwise, the following applies to the analysis of gas supply agreements (GSAs) and offers and bids in chapter 2:

- The 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 the 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.

The following entities were classified as 'retailers': Origin Energy, AGL, EnergyAustralia, Alinta Energy, Shell Energy Australia and Macquarie Bank.

The 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.

As noted in chapter 1, gas suppliers in the Northern Territory supply gas into the East Coast Gas Market via the Northern Gas Pipeline (NGP). We include Northern Territory suppliers' prices in the analysis in this chapter only where gas is delivered into the East Coast Gas Market. Due to the relatively high transport cost component involved in delivering Northern Territory gas to the East Coast Gas Market, it is less meaningful to compare prices for gas that is delivered to an east coast customer in the Northern Territory.

A.2 Reporting on offers and bids

The information in this section describes the ACCC's approach to reporting on offers and bids, as presented in section 2.4 of chapter 2, and should be read in conjunction with information above in section A.1.

The following also applies to the 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.¹⁴⁸

- 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, 2020) 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.

A.3 Comparing domestic price offers with contemporaneous expectations of future LNG netback prices

In section 2.5 of this report, the ACCC compares: quantity-weighted averages of offers with fixed pricing and a term of 1–3 years:

- quantity-weighted average offers (for those offers with fixed pricing and a term of 1–3 years) in Queensland relative to expectations of LNG netback prices in Queensland and the estimated forward costs of production in Queensland
- quantity-weighted average offers (for those offers with fixed pricing and a term of 1–3 years) in the southern states relative 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.

A.3.1 Approach for comparing offers made in Queensland

The ACCC calculates 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 producers 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 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.

¹⁴⁸ 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).
- 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 Japanese Customs Cleared (JCC) crude oil price is derived using the expected Brent crude oil price as a proxy.
- The expected Japanese 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 per cent thereafter.

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 the best indication of the likely opportunity cost of supplying gas to the domestic market¹⁴⁹
- used short-run incremental costs of LNG production and transport, since LNG producers 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.¹⁵⁰

The domestic offers analysed in section 2.5 of the pricing chapter are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2020 as an example, we calculated an average 2020 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 2020, and selling cargoes on the Asian LNG spot market in 2020.

For example, the ACCC calculated the average of LNG netback prices for 2020 that an LNG producer would have expected in July 2019 as follows:

- The ACCC obtained JKM futures prices for each month of 2020 that were quoted by ICE on each day during July 2019.
- The ACCC converted the monthly 2020 JKM futures prices into LNG netback prices at Wallumbilla by:
 - converting the prices from US\$/MMBtu into A\$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ, and
 - subtracting the short-run marginal costs of shipping, liquefaction¹⁵¹ and transportation.¹⁵²
- The ACCC averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2020 expected on each day during July 2019.
- The ACCC then averaged these 2020 expectations for each day of July 2019 to arrive at an average of LNG netback prices for 2020 expected during the month of July 2019.

As has been noted before, the ACCC's 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 producers, 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

¹⁴⁹ For this, the ACCC has used futures prices of the Japan Korea Marker (JKM) quoted by the Intercontinental Exchange (ICE).

¹⁵⁰ ACCC, Guide to the LNG netback prices series, <https://www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20October%202018.pdf>.

¹⁵¹ We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG producers in Queensland.

¹⁵² We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.

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 producers 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 in recent months, 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.¹⁵³

A.3.2 Approach for comparing offers made 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, and
- 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

¹⁵³ Ferrier Hodgson, *National Resources Insights*, 2017

buyer/seller alternative range in that specific location. In the analysis in chapter 2, we present a buyer and seller alternative for Victoria.

The ACCC notes 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 terms and conditions in GSAs, the contract length and, in the case of retailer offers, retailer costs and margins.

A.3.3. Forward costs of production

In 2018, the ACCC engaged Core Energy (Core) to develop detailed estimates of the gas production costs facing producers in the East Coast Gas Market.¹⁵⁴ 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.

The analysis in section 2.5 of chapter 2 compares price offers for 2020 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. The ACCC has 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, the ACCC chose the Middle Surat and Roma Shelf supply region as it has material uncontracted 2P reserves (9260 PJ) that Core expected to be in production in 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 in above, the marginal supplier in Victoria comes into the analysis in the circumstances 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 this chapter, the ACCC has 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 2017.¹⁵⁵

A.4 Reporting on Gas Supply Agreement pricing

This section of the appendix details the ACCC's approach to reporting on prices under Gas Supply Agreements (GSAs) entered into by gas producers and retailers.

¹⁵⁴ Core Energy, Gas Production Cost Estimates: Eastern Australia, 2018
<https://www.accc.gov.au/system/files/Core%20Energy%20report%20for%20ACCC%20-%20November%202018.pdf>.

¹⁵⁵ The ACCC intends to update the assumptions and costs estimates for future reports using data published by AEMO on production costs in the East Coast Gas Market.

A.4.1 Approach to creating the GSA time series

The GSA price time series presented in section 2.6.1 of chapter 2 includes GSAs executed between gas suppliers and C&I gas users (that is, excluding retailers, LNG producers and GPG gas users).

For this series, the ACCC:

- included GSAs executed at arm's length
- included GSAs from both producers and retailers
- included GSAs for delivery across the whole of the east coast (i.e. Queensland and the Southern States)
- included GSAs for supply with a total contracted quantity of at least 0.5PJ and for a term of at least 12 months
- included only fixed price GSAs (i.e. excluded any GSAs linked to oil or JKM). Oil and JKM-linked contracts have been excluded from this analysis, as expectations around future oil and North Asia LNG prices can be markedly different
- excluded GSAs with non-price terms and conditions that are not reflective of the market as a whole
- calculated a quantity-weighted average nominal price of each GSA using the base commodity price (i.e. not including separate transportation or other ancillary charges) and the annual contract quantity specified in the GSA for the first year of supply
- calculated a half yearly quantity-weighted average based on all the applicable GSAs that were executed in that half yearly interval, irrespective of the term of the GSA.

A.4.2 Approach to reporting on prices agreed to under GSAs

The information in this box should be read in conjunction with information in box 2.1. The following also applies to the analysis of prices agreed under 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.
- In contrast to the preceding analysis of offers and bids, we estimated prices under GSAs using assumptions relating to key variables, including, where relevant, AUD/USD, inflation, Brent Crude oil and the Platts Japan Korea Marker (JKM). The assumptions used in this report are based on market expectations for those variables for 2020 and 2021:
 - These market expectations have changed since we last reported on GSA prices. AUD/USD exchange rates and inflation, for example, are expected to be lower than was expected. A reduction in inflation reduces expected GSA prices, while a reduction in the AUD/USD increases expected GSA prices (as oil and JKM prices are denominated in USD). The net effect of the change in expectations is lower expected GSA prices than would be expected using our previous assumptions.
- As in the case of the offers analysis above, the reported prices are based on the wholesale commodity price of gas and do not include separate charges for transporting gas to the user's location or any other ancillary costs. In some instances, however, transport and other costs may be bundled into a single wholesale gas price. This is accounted for in the analysis by categorising GSA prices by the location of the delivery point rather than the location of the source of the gas.

- In addition to average prices, we are also reporting corresponding average load factors and take or pay quantities. Both the load factor and take or pay multiplier are a measure of the level of flexibility allowed under the contract:
 - 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 per cent 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 per cent is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

Consistent with the approach adopted in previous reports, we categorise GSA prices by the location of the delivery point rather than the location of the source of the gas.

Glossary

ACCC's 2015 inquiry: The ACCC's inquiry into the East Coast Gas Market in 2015, as reported on in April 2016.

AEMO-operated wholesale markets: There are two broad kinds of AEMO-operated wholesale markets: demand hubs, and supply hubs. The Victorian Declared Wholesale Gas Market (DWGM) and the Adelaide, Sydney, and Brisbane Short-Term Trading Markets (STTMs) can be considered demand hubs as their primary purpose is to meet the gas requirements of a particular demand centre. These markets are compulsory—if a user sits within the defined boundaries of the market, their gas use (or supply) will be scheduled through the market by AEMO. The Wallumbilla and Moomba Gas Supply Hubs were developed primarily to facilitate the trade of gas between suppliers and large users at a particular supply centre. These markets are voluntary.

Aggregator: an entity other than a gas retailer that purchases gas for the purpose of re-supply to end users (including C&I users and GPG) rather than for their own consumption.

Banking rights: A contractual term relating to a gas user's maximum gas usage allowance in a given period. When a gas user consumes less than their maximum, banking rights determine the extent to which the user may 'bank' the difference for later use.

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.

Delivered ex-ship price: The price of gas delivered by ship to a destination port. This term is typically used for LNG prices.

Domestic demand: The quantity of gas demanded by users located in Australia.

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.

Free on-board price: The price of gas loaded on a ship at a port connected to an LNG plant.

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 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.

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.

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.

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.

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.

Reserves and resources

Reserves: Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

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.

Southern States: South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Spot market/transaction: One-off transactions, as distinct from transactions occurring under supply contracts.

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.

Transportation and storage related terms:

Contracted but un-used capacity: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

Gas storage service: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

Secondary capacity: Capacity that is on-sold by primary capacity holders on a pipeline.

Shipper: A user or prospective user of pipeline services.

Unfulfilled offer: A written offer for supply of gas that does not result in an agreement to supply gas.

Units of Energy

Joule—a unit of energy in the International System of Units

Gigajoule (GJ)—a billion (10^9) joules

Terajoule (TJ)—a trillion (10^{12}) joules

Petajoule (PJ)—a quadrillion (10^{15}) joules

Million British Thermal Units (MMBtu)