



Gas inquiry 2017-2020

Interim report

December 2018

Australian Competition and Consumer Commission

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Acronyms

ACT	Australian Capital Territory
ACQ	annual contract quantity
ADGSM	Australian Domestic Gas Security Mechanism
C&I	commercial and industrial
CAGR	compound annual growth rate
CPI	Consumer Price Index
CSG	coal seam gas
DES	delivered ex-ship
DWGM	Declared Wholesale Gas Market
EBITDA	earnings before interest, tax, depreciation and amortisation
EOI	expression of interest
ESO	Energy Supply Outlook
ESOO	AEMO's Electricity Statement of Opportunities
FID	financial investment decision
FOB	free on board
FSRU	floating storage regasification unit
GBB	Natural Gas Bulletin Board
GJ	Gigajoule
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSG	Gas Supply Guarantee
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
JCC	Japanese Customs-Cleared Crude
JKM	Japanese Korea Marker
JV	joint venture
LNG	liquefied natural gas
MCQ	minimum contract quantity
MDQ	maximum daily quantity
MFN	most favoured nation

MMBtu	Million British Thermal Units—see below, Units of Energy
MPH	Moomba Processing Hub
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSW	New South Wales
NT	Northern Territory
PJ	Petajoule
QLD	Queensland
REPI	Retail Electricity Pricing Inquiry
SA	South Australia
STTM	Short-term trading market
TJ	Terajoule
VIC	Victoria
WA	Western Australia
Organisations	
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
AGL	AGL Energy, originally the Australian Gas Light Company
AETV	Aurora Energy Tamar Valley
APA	APA Group
APLNG	Australia Pacific LNG Pty Ltd
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
BHP	BHP Billiton, formed from a merger of BHP (originally the Broken Hill Propriety Company) and Billiton
CNOOC	China National Offshore Oil Corporation
COAG	Council of Australian Governments
EIA	Energy Information Agency (US)
FERC	Federal Energy Regulatory Commission (US)
GBJV	Gippsland Basin Joint Venture

GLNG	Gladstone LNG
GMRG	Gas Market Reform Group
ICE	Intercontinental Exchange
OCE	Office of the Chief Economist
PRMS	Petroleum Resources Management System
PWC	Power and Water Corporation
QCLNG	Queensland Curtis LNG Project
QGC	QGC Pty Limited, previously Queensland Gas Company
RLMS	Resource and Land Management Services
SEA	Shell Energy Australia
SEC	Securities and Exchange Commission (US)
SGH	Seven Group Holdings
Pipelines	
BWP	Berwyndale to Wallumbilla Pipeline
CGP	Carpentaria Gas Pipeline
CRP	Central Ranges Pipeline
CRWPL	Comet Ridge to Wallumbilla Pipeline Loop
CWP	Central West Pipeline
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
QSN Link	Queensland to South Australia/New South Wales Link
RBP	Roma to Brisbane Pipeline
SEAgas	South East Australia Gas pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline

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.

April 2018 report: the ACCC's third interim report, published in April 2018, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

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.

December 2017 report: the ACCC's second interim report, published in December 2017, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

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.

July 2018 report: the ACCC's fourth interim report, published in July 2018, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

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.

Transportation and storage related terms:

Contracted but un-nominated capacity: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

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 of pipeline services.

September 2017 report: the ACCC's first interim report, published in September 2017, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

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.

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)

Overview

This is the fifth interim report of the Australian Competition and Consumer Commission's (ACCC) inquiry into gas supply arrangements in Australia (the Inquiry). The ACCC has maintained its focus on the operation of the East Coast Gas Market, where there continue to be both immediate and longer-term concerns.¹

In the July 2018 report, the ACCC reported on the gas supply outlook in the East Coast Gas Market for 2019. The ACCC found that there was unlikely to be a gas supply shortfall in 2019 based on the supply forecasts from producers and domestic demand forecasts from the Australian Energy Market Operator (AEMO). The ACCC also found that the Queensland LNG producers² were expecting to have gas in excess of their contractual requirements, which they could sell domestically.

The ACCC also observed that although domestic prices converged with expected LNG netback prices at Wallumbilla for 2019, they remained at levels that threatened the long-term viability of many commercial and industrial (C&I) gas users.

While there have been some minor revisions of gas supply forecasts by producers, the risk of a gas supply shortfall in 2019 remains largely unchanged. Sufficient gas is expected to be produced in the East Coast Gas Market to meet expected export and domestic demand.

Despite this, domestic gas commodity prices have continued to increase in line with export parity prices. By August 2018, most offers were priced at, or above, the mid-\$10/GJ level. These prices are lower than those that were observed in 2017. However, following a significant upward shift in gas prices over the past few years, many C&I gas users are now facing very challenging long-term investment decisions. It appears increasingly likely that some C&I gas users will relocate from the east coast or close their operations.

There are still constraints impeding the efficient flow of gas across the east coast. Current pipeline tariffs remain too high. Measures to address the monopoly pricing by pipeline operators have commenced, but are not yet in full effect. While it is too early to assess the impact of these measures on the market, evidence is beginning to emerge that these reforms are improving price discovery and putting downward pressure on prices for pipeline services. However, some further refinement of the information disclosure requirements, and greater scrutiny of the information published by pipeline operators pursuant to those requirements, may be necessary.

The ACCC is currently conducting a review to examine how the costs and margins of the three largest gas retailers (AGL, EnergyAustralia and Origin) are affecting the delivered price of gas paid by their customers. Preliminary results indicate that the retailers have earned material margins on gas sales over 2014–2017. However, the ACCC emphasises that these are highly aggregated preliminary results, which require further examination. The ACCC will continue to conduct its review and will report on its findings in its 2019 interim reports.

The long-term gas supply outlook in the East Coast Gas Market remains uncertain and heavily influenced by the LNG producers that control the bulk of reserves and resources in the market. There are significant uncontracted 2P reserves in the Surat and Bowen basins in Queensland. The timing of the development of these reserves is critical for the East Coast

¹ The East Coast Gas Market currently includes Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania. We also monitor the flow of gas from the Northern Territory into the east coast through the Northern Gas Pipeline. This report does not cover Western Australia for reasons set out in the September 2017 report.

² There are three LNG projects in Queensland: Australia Pacific LNG (APLNG), Queensland Curtis LNG (QCLNG) and Gladstone LNG (GLNG). We also refer to them as 'LNG exporters' or 'LNG projects' throughout this report.

Gas Market. It will depend on a number of factors, including the performance of the coal seam gas (CSG) wells, production costs, gas prices and, crucially, choices made by the LNG producers on how much gas to supply into the domestic and export markets.

The users in the Southern States are likely to become increasingly reliant on gas from Queensland due to substantially smaller quantities of uncontracted reserves and little prospect of new developments in the near term. In part, this is due to moratoria and regulatory restrictions relating to onshore gas development in Victoria, NSW and Tasmania.

Despite strong signals, investment in gas development and key transmission infrastructure has been disappointingly slow to respond. While, in aggregate, suppliers plan to increase their investment in exploration activities compared to the last few years, in 2019 and 2020 these are not expected to reach the levels observed five years ago. Shippers are currently not entering into long-term gas transportation agreements (GTAs) to underwrite pipeline expansion on key transmission pipelines linking Queensland to the Southern States. Despite the growing importance of storage in the market, there has been limited investment into additional storage capacity.

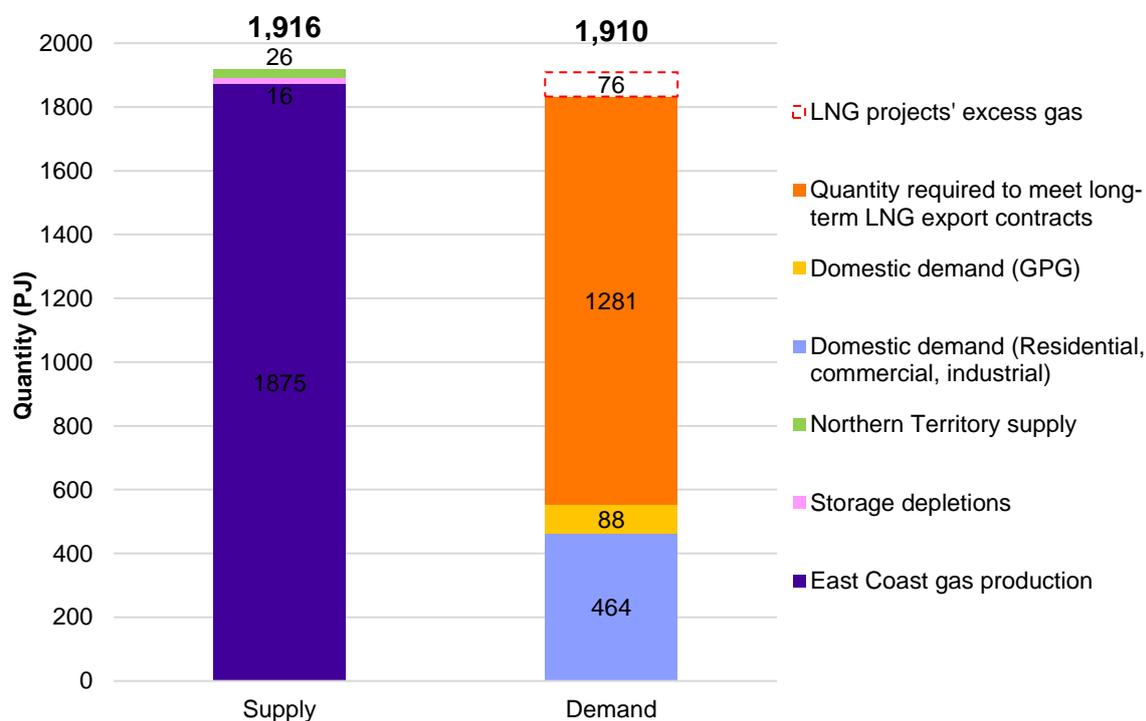
To function more effectively, the East Coast Gas Market requires a greater level and diversity of supply, greater transparency and a more efficient transportation network. For the remainder of the Inquiry, the ACCC will continue to focus on these issues and monitor the actions of market participants across the entire supply chain. The ACCC will also continue to improve transparency in the East Coast Gas Market by publishing key market information, monitoring the effectiveness of reforms and monitoring the operation of the market. While this will assist C&I gas users to make more informed investment decisions, greater investment in gas development and infrastructure is the key to addressing the immediate and longer-term concerns in the East Coast Gas Market.

Sufficient gas supply is expected in 2019 to meet forecast demand in the East Coast Gas Market

The east coast supply outlook for 2019 has not changed materially since the ACCC's July 2018 report. Chart 1 shows that sufficient gas is expected to be produced in the East Coast Gas Market to meet expected export and domestic demand.³

³ ACCC used forecasts of east coast domestic demand from AEMO's June 2018 GSOO.

Chart 1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2019



Source: ACCC analysis of data obtained from producers and of data from AEMO's June 2018 GSOO.

Note: Totals may not add up due to rounding.

The construction of the Northern Gas Pipeline (NGP) has been completed and first gas is expected to flow into the east coast by the end of 2018.⁴ The Sole Gas Project in the Gippsland Basin is also still expected to commence gas production in 2019, bringing additional supply into the market.

The Queensland LNG producers currently forecast to have 76 PJ of gas in excess of their export and domestic contractual requirements, which they can sell domestically or overseas. This gas will likely act as a buffer should domestic demand on the east coast be higher, or gas production lower, than currently forecast.

On 28 September 2018, the Australian Government and the Queensland LNG producers agreed to a new Heads of Agreement, replacing the agreement made on 3 October 2017. Under the terms of the new agreement, the LNG producers agreed to offer uncontracted gas to the domestic market in the event of any supply shortfalls in 2019 and 2020.⁵ The LNG producers agreed that they would offer this gas on reasonable terms.

The supply outlook in the Southern States for 2019 is largely unchanged since the ACCC's July 2018 report. However, it remains subject to realised demand for gas from gas powered generators (GPG), which is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, renewal generation investment, unexpected retirement of generation or unplanned outages).

⁴ C Murray, *Northern Gas Pipeline construction complete*, Jemena, <http://jemena.com.au/about/newsroom/media-release/2018/northern-gas-pipeline-construction-complete>.

⁵ Canavan, M (Minister for Resources and Northern Australia), *New Heads of Agreement to secure gas supply*, media release, Parliament of Australia, 30 September 2018. <https://www.minister.industry.gov.au/ministers/canavan/media-releases/new-heads-agreement-secure-gas-supply>.

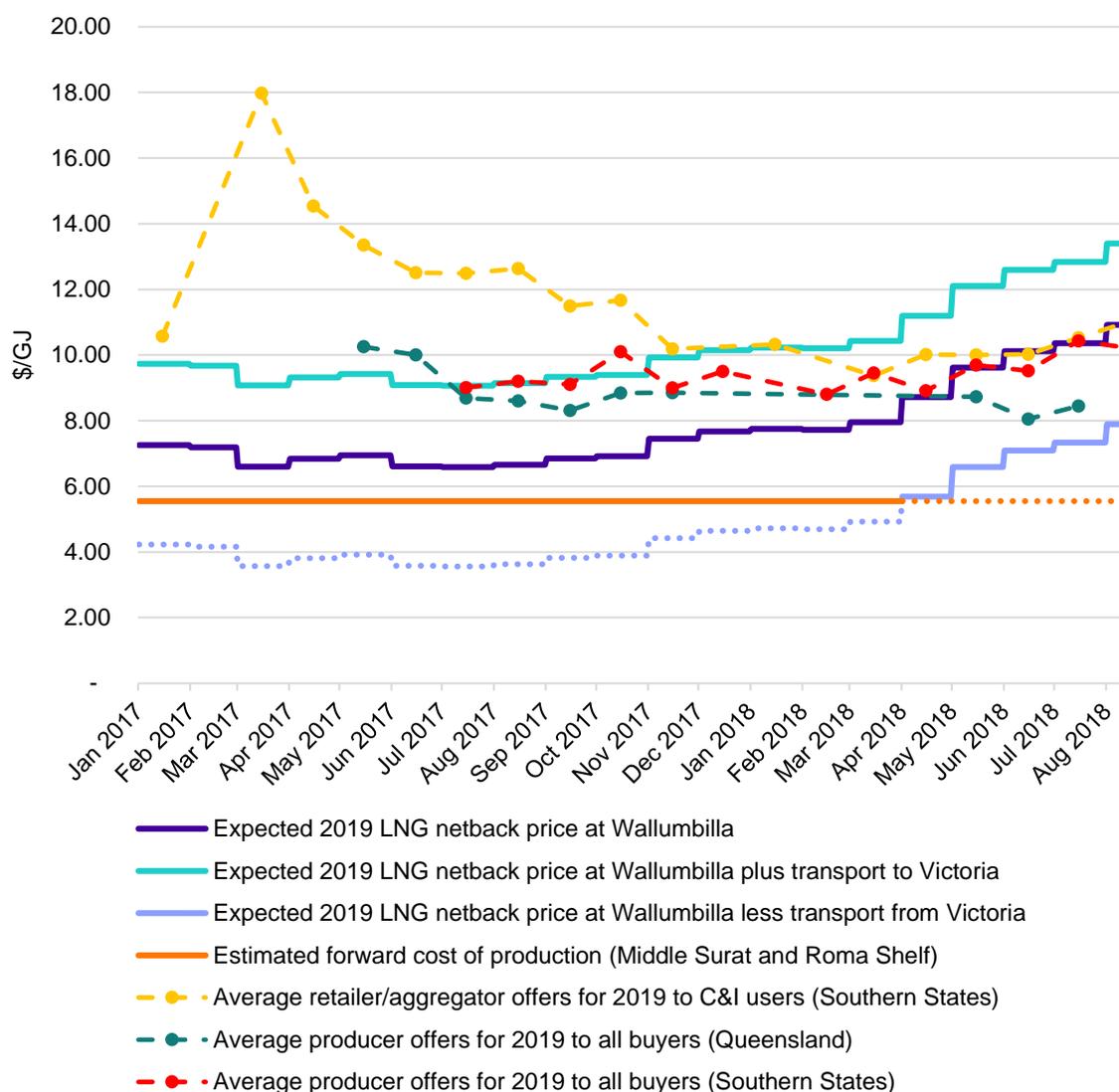
Domestic gas prices for 2019 are tracking the expected LNG netback prices at Wallumbilla, but C&I gas users continue to face challenging decisions about their ongoing operations

As we reported in the July 2018 report, a number of short-term factors came together in 2017 to significantly disrupt the operation of the East Coast Gas Market at a time when it was already undergoing significant change. As a result, gas prices offered by suppliers in the East Coast Gas Market in 2017 were well in excess of export parity prices and there was a significant gap in prices being offered by retailers/aggregators and gas producers.

In the July 2018 report, we observed that early price data for 2019 indicated that the short-term factors had eased. By the end of the first quarter of 2018, the prices offered in the domestic market for gas supply in 2019 had converged with export parity prices.

Chart 2 shows that this trend has continued to the end of August 2018.

Chart 2: Averages of monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices



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

Notes: JKM futures prices quoted by ICE before June 2017 related to futures contracts for the first half of 2019 only. Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

As the chart shows, expected LNG netback prices at Wallumbilla for 2019 increased from around \$9/GJ towards the end of April 2018 to over \$11.50/GJ by the end of August 2018. Over the same period, gas commodity prices offered by all suppliers in the domestic market for gas supply in 2019 ranged from \$9/GJ to \$12/GJ. By August 2018, most offers were at, or above, the mid-\$10/GJ level, including several offers above \$12/GJ. Gas commodity prices under gas supply agreements (GSAs) entered into by all the suppliers in the east coast over this period also ranged from \$8.50/GJ to \$11.95/GJ.

Commodity gas prices charged by retailers/agggregators to C&I gas users remain, on average, higher than commodity gas prices charged by gas producers. However, this gap has narrowed compared to 2017. In the period April 2018 to August 2018, some retailers entered into GSAs with C&I gas users at lower prices than producers.

The convergence between domestic gas commodity prices and LNG netback prices at Wallumbilla, as well as the convergence between gas commodity prices charged by retailers/aggregators and gas producers, are positive developments in the East Coast Gas Market. These developments indicate that domestic gas prices are now more reflective of the underlying supply-demand dynamics than they were in 2017.

The expected LNG netback prices at Wallumbilla for 2019 have also fallen significantly in recent months. After reaching a peak of around \$12.50/GJ in September 2018, expected LNG netback prices fell to \$9/GJ by the end of November 2018.

However, at current levels of domestic pricing, these developments provide little comfort to C&I gas users. Gas is a feedstock to production or largely irreplaceable source of energy for a diverse range of sectors such as mining, manufacturing, chemicals, agriculture and food production. With domestic gas commodity prices now edging well in excess of \$10/GJ, many C&I gas users are facing very challenging long-term investment decisions. It appears increasingly likely that some C&I gas users will relocate from the east coast or close their operations.

“Prices are unsustainably high and unless resolved, represent a challenge to the ongoing competitiveness and sustainability of [our Australian] operations.”

Large east coast gas user, October 2018

Some C&I gas users are increasingly re-contracting for shorter periods and much closer to the end of their existing GSAs, hoping that domestic gas prices may ease. Of those C&I gas users that are seeking longer-term GSAs, very few are receiving offers for terms that match their requested duration. Further, some C&I gas users are not receiving many firm offers for supply from 2020 onwards, with some suppliers not prepared to commit to supplying beyond 2019.

While access to reasonably priced transportation services remains inadequate, early results following the recent reforms are encouraging

The ACCC’s 2015 inquiry found evidence of a large number of existing pipelines engaging in monopoly pricing, which resulted in higher delivered gas prices for users and associated adverse effects on economic efficiency.⁶ In response, a new information disclosure and arbitration framework for previously unregulated (non-scheme) pipelines was introduced on 1 August 2017.

The new framework aims to constrain the exercise of market power by pipeline operators by requiring them to disclose more information that can assist shippers during negotiations and by providing a credible threat of intervention if negotiations fail. Since its introduction, there has been one arbitration, between the Tasmanian Gas Pipeline (TGP) and AETV Pty Ltd (a subsidiary of Hydro Tasmania). Following the final determination on 12 April 2018, AETV entered into a GTA with TGP. TGP subsequently published standing prices, which are based on the arbitrated outcome.

While it is too early to assess the impact of the arbitration framework on the market, the results of the first arbitration appear to be positive. As a foundation shipper, AETV already had one of the better deals of the shippers on this pipeline, but was able to achieve an even lower price through the arbitration process. Another shipper appears to have benefited as well, negotiating a GTA this year at a price that is close to 60 per cent lower than under its previous GTA. The invoiced price currently paid by this shipper is still higher than the latest

⁶ ACCC, *Inquiry into the east coast gas market*, April 2016, p. 92.

standing price published by the TGP, so this shipper should have an opportunity to negotiate a lower price when it re-contracts in the future.

The information disclosure requirements under the new framework commenced in 2018. They require non-scheme pipeline operators to publish the information that shippers need to make an informed decision about whether to seek access to a pipeline service and to assess the reasonableness of an offer made by the pipeline operator. This includes service and access information, standing prices, weighted average prices and a range of financial information (including asset valuations).

In the past, the shippers' main source of pricing information would have been the price the shipper previously paid for the same service. For many pipelines, there was no standing price and, given most pipelines are monopolies, there were no competitive offers from other service operators to use for comparison. We expect that the additional pricing and financial information will aid shippers during the price discovery process and should enable many to negotiate better deals with pipeline operators when they re-contract in the future.

The ACCC has already observed that, over the past 12 months, some shippers have been able to negotiate lower prices for firm transportation, interruptible transportation and other services as well as greater service flexibility. While it is unclear whether these developments are due to the recent reforms or other factors, they are nevertheless positive for the market.

Despite some benefits of the transportation reforms becoming evident, current transportation prices are still too high. This is in part due to the time it will take for these reforms to take full effect, with many shippers continuing to pay prices under GTAs that were negotiated prior to the commencement of the reforms. These shippers will not see the full benefit of these measures until they seek to re-contract in the future.

Further, it is unclear whether the information disclosure requirements are working as intended. The ACCC has observed that some standing prices published by pipeline operators are higher than the invoiced prices paid by shippers and has previously observed some deficiencies in the pricing methodologies published by some pipeline operators. Given the importance of these disclosure requirements to address information asymmetries in the market, the ACCC will conduct a close review of this information to determine whether the disclosure requirements need to be refined or if greater oversight of the information published by pipeline operators is required.

More broadly, the ACCC intends to continue monitoring the effectiveness of the reforms over the remainder of the Inquiry. As part of this process, the ACCC will review the information that pipeline operators are required to disclose, including weighted average prices, financial reports and asset valuations. The ACCC is concerned that some of the financial information recently published by pipeline operators would appear to suggest that they have not recovered any of their original capital investment. These valuations are surprising given pipeline operators have previously provided information, including to the ACCC's 2015 inquiry, indicating that investments are ordinarily fully underwritten by shippers through medium to long-term GTAs and they do not tend to build capacity on a speculative basis. The ACCC will undertake a more detailed review to test the veracity of this information in 2019.

There remain pipeline capacity constraints impeding the efficient flow of gas across the east coast. In particular, new shippers are still constrained in their ability to move gas from Queensland into Adelaide or Sydney due to the contractual congestion on key transportation routes. The ACCC is aware that some pipeline operators have taken steps to alleviate these constraints. One pipeline operator, for example, de-contracted capacity from an existing long-term shipper, which the shipper was unable to utilise, and contracted that capacity to another shipper. Looking forward to 2019, we would expect to see more secondary capacity

trading on these pipelines once the capacity trading reforms are implemented on 1 March 2019.

In addition, if suppliers are able to access reasonably priced storage capacity in the Southern States, they can use it to manage the flow of gas from Queensland more efficiently. Suppliers would be able to transport gas from Queensland during off-peak periods and store it until required. Given the increasingly important role of storage in the market, the ACCC has commenced monitoring storage prices paid by capacity holders of the Victorian Iona underground storage facility and Dandenong LNG storage facility. In addition, the ACCC considers that storage operators should be required to disclose more information about their prices and the contracted position of their facilities.

The ACCC is conducting a review of retailers' costs and margins

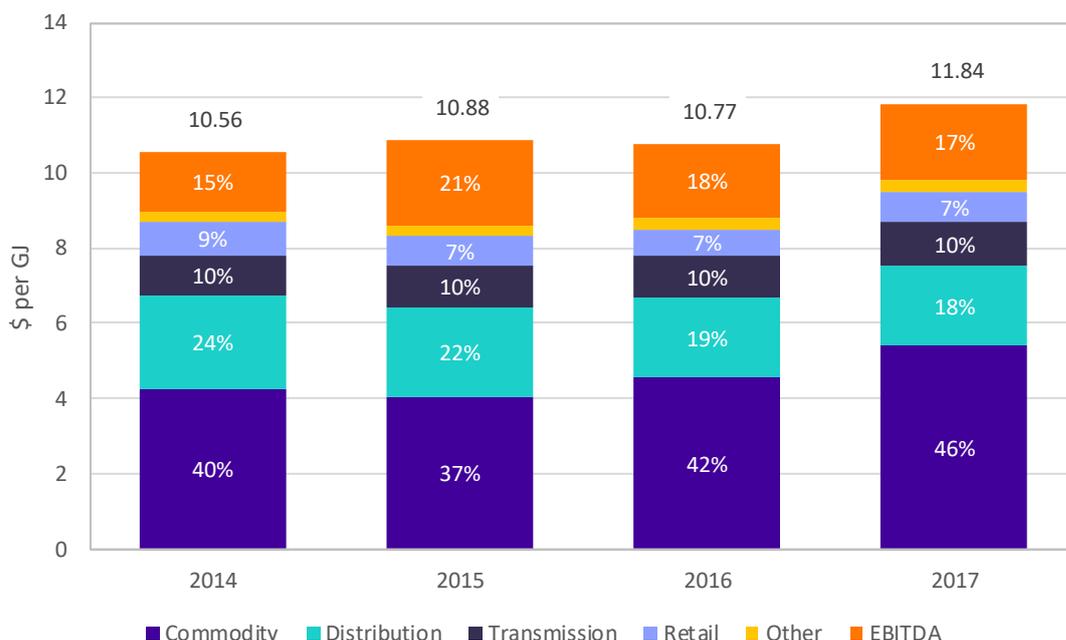
The ACCC is currently conducting a review to understand how the costs and margins of the three largest gas retailers (AGL, EnergyAustralia and Origin) have affected the delivered price of gas paid by their customers over the period from 2014 to 2017. The ACCC is reporting on its review in two stages. In this report, we have set out our preliminary findings about the aggregated costs and margins of the three retailers. In future interim reports, we will report our findings of a more detailed examination of these matters at a jurisdictional level and by customer type.

The retailers incur a range of costs in supplying their customers. The main categories of costs include the commodity costs for procuring gas, transmission and distribution costs for transporting gas from its source to the customer's location, storage costs for storing gas in dedicated storage facilities, operating costs for servicing existing customers and acquiring new customers, and costs for participating in domestic short-term trading markets.

The retailers supply gas to a range of customers across the east coast. The ACCC has obtained information from the three retailers relating to the costs incurred, and the revenues received, in supplying the following customer segments: residential customers and small to medium enterprises, C&I gas users, the retailers' own GPG, and wholesale customers (those connected to a transmission pipeline, including large C&I gas users, the LNG projects and other retailers).

Chart 3 presents the preliminary results, for the entire customer base of the three retailers combined.

Chart 3: The delivered price of gas⁷ paid by the customers of AGL, EnergyAustralia and Origin, broken down by each cost component and the retailers' margin⁸



Source: ACCC analysis of information provided by retailers.

Note: In this chart, 'retail' costs refer to the retailers' operating costs, while 'other' costs include costs associated with storage and the costs of participating in AEMO-operated Wholesale Markets. Not all cost categories presented in this chart are applicable to all the customer segments – for example, retailers would not typically incur distribution costs in supplying wholesale customers.

Chart 3 shows that the average EBITDA earned by the three retailers across the east coast and across all customer segments ranged from \$1.60/GJ to \$2.29/GJ over the period from 2014 to 2017 and accounted from 15 to 21 per cent of the delivered price of gas. While this appears to indicate that the retailers were making material margins in this period, the ACCC emphasises that these are highly aggregated preliminary results, which require further examination. Separate analysis shows that the costs incurred and the EBITDA earned differ across the retailers and can also vary across customer types and locations.

The ACCC will continue to conduct its review to understand, for each retailer, the trends in the costs incurred, the drivers behind the observed margins and how these flow through to the different customer segments. In particular, the ACCC will seek to understand the extent to which the observed margins may relate to:

- market factors, including supply-demand dynamics and rising gas prices
- the circumstances of each retailer, particularly their risk profile
- the level of competition to supply different customer segments, in different locations
- barriers impeding new entry or effective competition between the incumbent retailers, such as the extent to which new or existing retailers are able to access necessary infrastructure (such as pipeline capacity).

⁷ The 'delivered price of gas' was calculated by taking the revenue received from all customers of the three retailers and dividing by the quantity (in GJ) supplied to all customers.

⁸ The ACCC has calculated the retailers' margin using an approach consistent with a calculation of earnings before interest, tax, depreciation and amortisation (EBITDA) by businesses.

The ACCC will also examine the transparency of the retailers' charges, including how the retailers represent this information to customers. The ACCC will provide an update on its review in its 2019 interim reports.

The long-term supply outlook remains uncertain and is heavily influenced by the decisions of the LNG producers in Queensland

The longer-term supply outlook for the East Coast Gas Market remains uncertain. Current forecasts indicate that sufficient gas is expected to be produced to meet forecast demand in the near- to medium- term. However, this is subject to expectations about the timing of production from undeveloped reserves being realised. This is less certain than production from developed reserves as gas is expected to be recovered from new wells, the performance of which is not yet known. In the medium-to-longer term, suppliers will need to develop contingent resources. Timing of production from these resources is even more uncertain, as contingent resources are more technically difficult to extract than reserves and may require construction of additional infrastructure, such as treatment facilities and/or pipelines.

There are material risks on the demand side too. The LNG producers currently do not expect to fully utilise their LNG trains' maximum sustained LNG output capacity over the period from 2020 to 2030. However, if LNG prices remain high or increase further, their incentives may change. The LNG producers could sell up to 3600 PJ of LNG above their contractual export commitments in this period. The LNG producers currently expect to sell about 1100 PJ on the LNG spot markets, which means that they currently expect to have enough spare capacity to sell up to 2500 PJ of LNG on top of this.

The decisions about the timing of development of reserves and resources in the east coast are largely concentrated in the hands of a handful of major gas producers. Over 80 per cent of 2P reserves and close to 65 per cent of 2C resources are held by the LNG producers in Queensland either through ownership or through purchases from other suppliers. Outside Queensland, the largest supplier in the Southern States, the Gippsland Basin Joint Venture (GBJV), accounts for the greatest proportion of 2P reserves (6 per cent) and contingent resources (4 per cent).

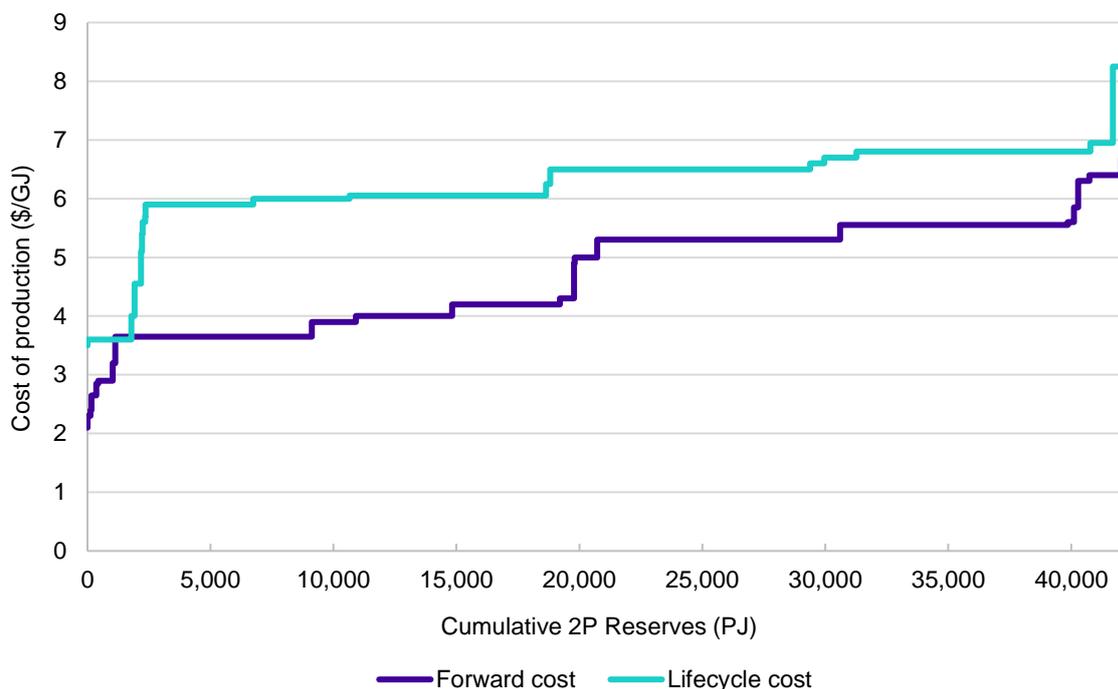
While the LNG producers will develop the bulk of their reserves in Queensland to meet their existing export commitments, they currently control a significant quantity of the 11 242 PJ of 2P reserves in the Surat and Bowen basins that remain uncontracted. The timing of the development of these reserves is critical for the East Coast Gas Market. It will depend on a number of factors, including the performance of the CSG wells, production costs, gas prices and, crucially, choices made by the LNG producers on how much gas to supply into the domestic and export markets. Outside Queensland, the bulk of uncontracted reserves in the east coast is in offshore Victoria (2185 PJ), which are largely held by the GBJV.

Virtually all of the uncontracted 2P reserves in Queensland are concentrated in the CSG fields. In the ACCC's 2015 Inquiry, the ACCC noted that the LNG producers encountered challenges in the initial stages of CSG development that put at risk their ability to sustain the required level of production over the period of their LNG export agreements.⁹ Substantial write-downs of CSG reserves over the 12 months to July 2018 indicate that those challenges are continuing. Arrow Energy has re-classified 2933 PJ of its 2P reserves across its Queensland coal seam gas fields into 2C resources, predominantly in the Bowen Basin. AGL has also re-classified a number of its 2P reserves into 2C resources in permit areas jointly held with Arrow. In addition, APLNG, Origin and Shell have written down reserves in some of their undeveloped areas.

⁹ ACCC, *Inquiry into the east coast gas market*, April 2016, p. 44.

Further, as shown in chart 4, production costs across the east coast are rising.

Chart 4: Lifecycle and forward cost estimates in the East Coast Gas Market (all 2P reserves)



Source: Core Energy.

Note: Lifecycle cost of production reflects the breakeven gas price for entire cash flows of a project, amortised over lifetime production volumes. Forward cost of production reflects the breakeven gas price for future cash flows of a project, amortised over future production volumes.

Based on Core Energy’s estimates, around 90 per cent of all 2P reserves in the east coast have a lifecycle cost of more than \$6/GJ.¹⁰ In large part, this is because the east coast is now heavily reliant on production from CSG, which is generally more expensive to produce than conventional gas due to the need for relatively high ongoing levels of capital expenditure.

However, over time there may be downward pressure on production costs associated with the development of CSG reserves as gas producers take advantage of new technologies, optimise CSG production and cut drilling costs.¹¹

There has also been a significant increase in the cost of production of conventional gas reserves. According to Core Energy’s estimates, lifecycle costs of conventional gas developments that have either begun production in recent years or are yet to commence, range between \$5.40/GJ and \$8.25/GJ.¹² The majority of these are in offshore Victoria,

¹⁰ The ACCC engaged Core Energy to develop production cost estimates for 2P reserves in the east coast. The full report is available on the ACCC’s website: <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/ing-netback-price-series>.

¹¹ The Australian, *Well, well, well: how Santos GLNG slashed costs, drilling times*, 23 March 2018, <https://www.theaustralian.com.au/business/mining-energy/well-well-well-how-santos-glng-slashed-costs-drilling-times/news-story/ac8b250817ae9e059820f68ef5177a8c>

¹² This includes the following developments: Kipper, Sole, Cooper Basin (undeveloped), Beach Energy West Gas, and Halladale, Blackwatch and Speculant.

where production sources are now shifting from the high volume, shallow depth, high-quality gas fields to low volume, deeper, low-quality gas fields.¹³

Despite strong signals for more investment in gas development and infrastructure, the response from the gas market is slow

Notwithstanding rising production costs, the high domestic gas prices remain well above the likely costs of production. Such prices, combined with high international LNG and oil prices, would usually encourage significant investment in gas exploration and development. In addition, increasing reliance by gas users in the Southern States on gas produced in Queensland, combined with contractual congestion on key transmission routes between Queensland and the Southern States, would usually encourage investment in expansion and extension of key transmission pipelines.

However, the gas market appears to be slow to respond. After falling to very low levels in 2016 due to plummeting oil prices, exploration activities are now beginning to recover. However, the number of exploration wells that suppliers expect to drill in the east coast in 2019 will still be 40 per cent lower than in 2013.

The level of gas exploration in offshore Victoria has been very low over the past few years and has not yielded any significant discoveries. In 2018, Esso drilled two exploration wells to explore a prospective area known as Dory, but was not able to find commercial quantities of gas.¹⁴ Over the next few years, suppliers plan very few additional offshore gas exploration activities in Victoria and no onshore activities in Victoria and NSW due to the current regulatory settings in those states. However, the National Offshore Petroleum Titles Administrator is currently conducting a review of southeast Australian offshore petroleum titles to determine if there are any offshore resources that could be brought into production.¹⁵

Producers and retailers/aggregators have been willing to enter into long-term GTAs to underwrite investment in new pipelines to link new or growing gas producing regions to the East Coast Gas Market. As mentioned earlier, Jemena has already constructed the NGP to link the Northern Territory to the east coast. Jemena has indicated that it could expand and extend the capacity of the NGP to transport up to 700TJ of gas each day if sufficient gas is developed in the Northern Territory.¹⁶ Jemena has also accelerated its plans to construct a new pipeline to link the Galilee Basin with the East Coast Gas Market.¹⁷

However, there has been very limited investment to expand pipeline capacity on the key transmission pipelines linking Queensland to the Southern States, notwithstanding that some of the pipelines are contractually congested. This appears to be largely due to existing and prospective shippers on those pipelines not entering into long-term GTAs to underwrite the required investment. The ACCC has found that in the period between 1 August 2017 and 30 August 2018, there were 26 new GTAs and variations resulting in new prices for firm forward haul services. Of these, 17 were for a term of one year or less, nine were for a term of between one year and five years and there were no terms of five years or more.

¹³ Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, November 2017, p. 6.

¹⁴ The Australian, *Exxon's 120m Bass Strait bed fails to deliver gas*, 15 November 2018, <http://online.isentialink.com/theaustralian.com.au/2018/11/14/6a31e122-dd19-43da-8bab-17cee22566f8.html>.

¹⁵ Canavan, M (Minister for Resources and Northern Australia), *Review of the S.E. Australian offshore petroleum leases*, media release, Parliament of Australia, 17 August 2018. Matt Canavan, 'Review of the S.E. Australian offshore petroleum leases', media release, 17 August 2018, <https://www.minister.industry.gov.au/ministers/canavan/media-releases/review-se-australian-offshore-petroleum-leases>.

¹⁶ Jemena, *Jemena welcomes call for greater investment in pipeline infrastructure*, <http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-call-for-greater-investment-in-pip>.

¹⁷ *ibid.*

This slow or limited investment response reflects a number of factors affecting decisions of market participants across all parts of the supply chain. Changing market fundamentals, structure and policy are affecting expectations about future gas supply, demand and prices. Measures introduced to address market failures, such as transportation reforms and other transparency measures, have not yet come into full effect. Other policy measures, such as moratoria and regulatory restrictions, are impeding gas exploration and development, while the possibility of the Australian Government exercising export controls appears to contribute to the short-term focus of some market participants. These factors are manifesting in reluctance by many market participants to commit to longer-term gas and transportation contracts.

The future for the East Coast Gas Market

There remain considerable challenges for the East Coast Gas Market in the medium-to-long term. To overcome these challenges and improve the efficiency of the market, the East Coast Gas Market requires a greater level and diversity of supply, greater transparency and a more efficient transportation network.

As we have previously advocated in our reports, more supply and greater diversity of suppliers are needed in the Southern States to bring domestic gas prices down. The most material pricing benefits for domestic gas users are likely to come if additional lower-cost gas is produced in the Southern States, rather than gas being transported from Queensland, the Northern Territory or imported via an LNG import terminal. For this reason, we continue to urge state governments to adopt policies that consider and manage the risks of individual gas development projects, rather than implementing blanket moratoria and regulatory restrictions.

There remains a need for greater transparency around the availability of, and prices for, gas and infrastructure, as well as of upstream activities, to improve the level of information available to market participants and prospective investors. This includes a need for increased and better reporting of reserve and resource information as well as information on uncontracted reserves and drilling activities. This would allow the market to respond more effectively to emerging supply issues.

As discussed earlier, a new information disclosure and arbitration framework for non-scheme pipelines has already been introduced and capacity trading reforms will commence on 1 March 2019. The ACCC will continue to make recommendations to the Australian Government to further improve transparency in the East Coast Gas Market.

As part of the current inquiry, the ACCC is also working to improve transparency in the East Coast Gas Market. For the remainder of the Inquiry, the ACCC will continue to:

- publish the prices offered and agreed for gas supply and the prices paid for transportation services
- regularly update the LNG netback price series, which the ACCC commenced publishing on its website on 2 October 2018¹⁸
- work on improving the transparency and quality of reported information on reserves and resources – the ACCC is currently developing a reporting framework that will provide for consistent reporting of reserves and resources and intends to consult on this framework, including the use of common price assumptions, in early 2019

¹⁸ ACCC, *Gas inquiry 2017-2020*, 16 November 2018, <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series>.

- review how the costs and margins of the three largest gas retailers are affecting the delivered price of gas paid by their customers and will report on its findings in more detail in future interim reports
- monitor the effectiveness of the transportation reforms and will review the information that pipeline operators are required to disclose, including the weighted average prices, financial reports and asset valuations.

Future work of the Inquiry

This is the fifth interim report of this Inquiry, which will operate until April 2020. The ACCC expects to provide the next interim report in April 2019 and three reports thereafter—in July 2019, December 2019 and a final report in April 2020.

In the April 2019 report, as well as each subsequent report, the ACCC will further promote gas price transparency by providing updates on prices offered and agreed for gas supply across the domestic market.

In the July 2019 report, the ACCC will report on the gas supply and demand outlook for 2020 as part of the advice to the Government under the Australian Domestic Gas Security Mechanism. The ACCC will also report on the experiences of C&I gas users in securing gas supply for 2020 and beyond.

In the December 2019 report, the ACCC will provide updates on the gas supply and demand outlook, C&I gas user experiences and the pricing of transportation services.

In the April 2020 report, the ACCC will finalise its recommendations to the Australian Government for continuing to implement measures to improve transparency in the gas market in Australia.

In addition to the regular reporting, the ACCC will publish its findings in relation to the areas it has been exploring over the course of the Inquiry, including:

- conditions for, and pricing of, access to transportation and storage services
- retailer pricing, costs and margins
- reserves and resources reporting
- key factors influencing domestic gas prices.

As mentioned earlier, the ACCC has commenced publication of the LNG netback price series on its website as one of the measures to improve transparency of gas prices in the East Coast Gas Market. Following publication of this report, the ACCC will add information on transportation charges and Core Energy's report on production costs to the website.

The ACCC will continue to make information available as appropriate.

1. Supply outlook

1.1. Key points

- The supply and demand outlook for the East Coast Gas Market in 2019 has not materially changed since the ACCC's July 2018 report. Based on current projections, the risk of a shortfall in 2019 remains low.
- The LNG projects expect to have 76 PJ of gas available in excess of their 2019 contractual commitments, which they can export or sell to the domestic market. In line with their commitment to the Australian Government, the LNG projects have agreed to first offer this gas domestically on competitive market terms before exporting it. This excess gas will likely act as a buffer should domestic demand on the east coast be higher, or gas production lower, than currently forecast.
- The LNG projects currently have no firm expectations of how much gas they will sell on the international spot markets above their contractual requirements in 2019.
- Between April 2018 and August 2018, the LNG projects did not enter into any new gas supply agreements for 2019. However, they did continue to contract for supply in 2018. We expect further contracting for 2019 supply to occur over the remainder of this year and into 2019.
- The supply outlook for 2019 in the Southern States remains tight, although forecast supply in the Southern States is expected to be sufficient to meet expected demand.
- The long-term supply outlook for the East Coast Gas Market from 2020 to 2030 remains uncertain. Whether supply is sufficient to meet demand continues to depend on:
 - the level of production that is realised, which will be significantly influenced by the performance of the CSG fields in Queensland
 - the success of development from contingent and undiscovered gas resources, the prospects and timing of which is highly uncertain
 - the level of domestic demand, expectations around which have fluctuated significantly over the last two years
 - the level of LNG exports, particularly the quantity of LNG spot sales.
- The LNG projects currently do not expect to fully utilise their LNG trains' maximum sustained LNG output capacity in the period 2020–30. Should they choose to do so, they could sell up to 3600 PJ of LNG above their contractual export commitments over this period.

1.2. Sufficient gas supply is expected in 2019 to meet forecast demand in the East Coast Gas Market

In July 2018, the ACCC reported that there was unlikely to be a shortfall in 2019. The LNG projects were forecasting to have 98 PJ of gas available in excess of their contractual commitments that could be sold domestically or exported. The ACCC found that, given the Heads of Agreement, this excess gas would likely act as a buffer for the domestic market if production forecasts were not realised or if demand was higher than expected.

On 28 September 2018, the Australian Government and Queensland LNG projects agreed to a new Heads of Agreement, replacing the previous agreement made on 3 October 2017.¹⁹

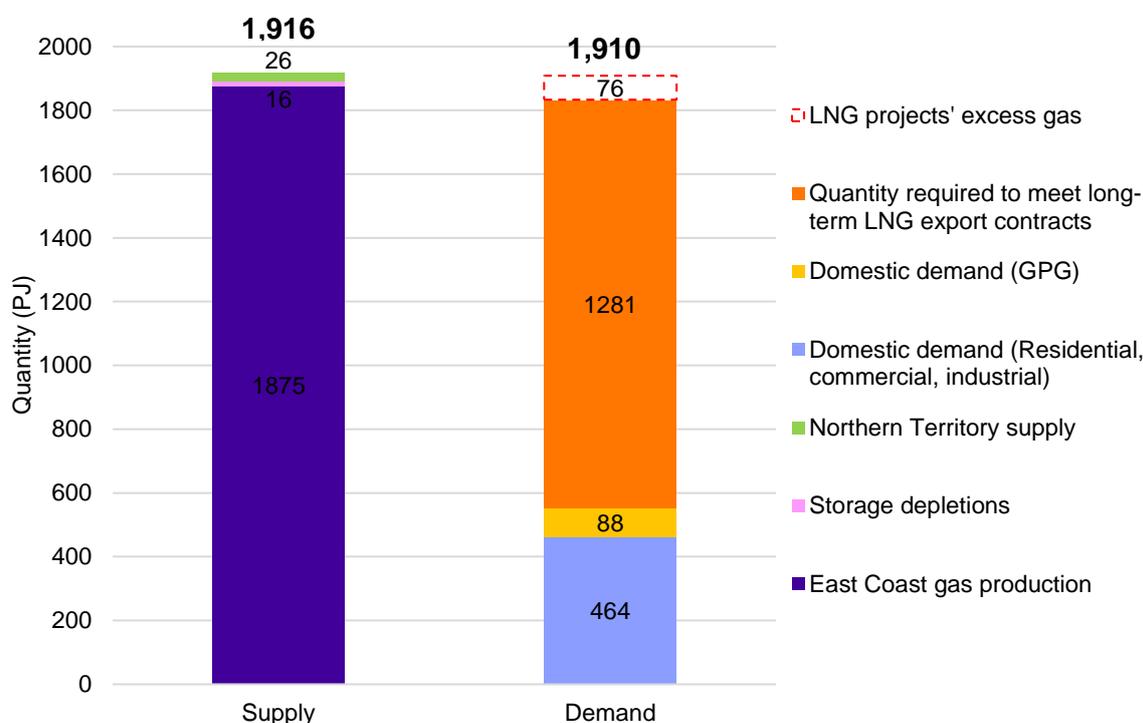
¹⁹ [Department of Industry, Innovation and Science, *Heads of Agreement – the Australian east coast domestic gas supply commitment*, 28 September 2018.](#)

The new agreement aims to “maintain a secure supply of gas to the east coast domestic market”.²⁰ Under the agreement, the LNG producers have committed to offer uncontracted gas to the domestic market in 2019 and 2020 to meet any expected supply shortfalls. The LNG producers have agreed to offer this uncontracted gas on reasonable terms and before offering it overseas.

Chart 1.1 shows the ACCC’s current supply and demand outlook for 2019. It shows total forecast supply (production, storage depletions and expected gas flows from the Northern Territory to the east coast in 2019) against total forecast demand (domestic demand plus the quantities of gas required by the LNG projects to meet their long-term export contractual commitments). The demand forecast includes the quantity of gas in excess of contractual commitments that the LNG projects forecast to have available in 2019.

The supply and LNG demand data reflected in the chart below is based on information obtained directly from producers. Domestic demand is based on AEMO forecasts and is unchanged since the July 2018 report.²¹

Chart 1.1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2019



Source: ACCC analysis of data obtained from gas producers as at August 2018 and of domestic demand data from AEMO’s June 2018 GSOO.

Note: Totals may not add up due to rounding.

<https://www.industry.gov.au/sites/g/files/net3906/f/heads-of-agreement-2018-prime-minister-and-east-coast-lng-exporters.pdf>.

²⁰ Canavan, M (Minister for Resources and Northern Australia), New Heads of Agreement to secure gas supply, media release, Parliament of Australia, 30 September 2018.

<https://www.minister.industry.gov.au/ministers/canavan/media-releases/new-heads-agreement-secure-gas-supply>.

²¹ Specifically, domestic demand is based on AEMO data from its June 2018 Gas Statement of Opportunities: https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf.

As the chart shows, the supply and demand outlook for 2019 has not changed materially since the ACCC's July 2018 report. Current projections indicate sufficient supply to meet domestic and contractual LNG export demand, although the supply-demand balance will tighten if forecast production is not realised, or if domestic or LNG demand is higher than expected.

Forecast supply has decreased from 1935 PJ to 1916 PJ. This is, in part, attributable to additional information received by the ACCC about the quantity of gas expected to flow from the Northern Territory into the east coast, but, more significantly, reflects decreases in forecast gas production by some of the key producers in Queensland and the Gippsland and Otway Basins.

As discussed further in sections 1.4 and 1.5, producers in the Gippsland and Otway Basins expect to produce 10 PJ less in 2019 than previously submitted to the ACCC. Producers in Queensland are also forecasting to produce less gas in 2019 than previously expected.

The Northern Territory will become connected to the east coast once commissioning of the Northern Gas Pipeline (NGP) is complete. The NGP, which is expected to be commissioned in late 2018, will enable up to 35 PJ of gas per annum to be transported to the east coast.²² The gas supply from the Northern Territory that has been included in the supply forecast for 2019 is based on firm gas supply commitments by suppliers in the Northern Territory to users in the east coast. Currently, about 26 PJ of gas is expected to flow to the east coast from the Northern Territory in 2019 (slightly less than what was reported in July due to new information).

Chart 1.1 takes into account forecast storage levels of the Roma Underground Gas Storage, Moomba, Silver Springs and Newcastle storage facilities. Overall, these facilities are expected to contribute an additional 16 PJ of gas to the total supply pool. Depending on the operation of other storage facilities, such as the Iona gas storage facility, there could be additional quantities of gas available to the East Coast Gas Market from those facilities in 2019.

The forecast production presented in chart 1.1 only includes production from 2P reserves. While most of this production is expected to come from well-known, developed areas, about eight per cent is expected to come from less certain, undeveloped areas. Production from undeveloped areas is expected to be recovered through new wells—the performance of which is not yet known—and may require approval of additional investments before production can commence (discussed further in chapter 2).

Chart 1.1 does not include production from contingent or undiscovered resources, which are highly uncertain and which require additional testing and investment. However, there is currently 13 PJ of gas forecast to be produced from contingent and undiscovered gas resources in 2019, which if realised, would contribute additional quantities of gas to the east coast.

Expected demand has decreased since July from 1912 PJ to 1910 PJ. This is attributable to lower expectations around the quantity of gas the LNG projects are likely to have available in excess of their minimum export and domestic commitments.

As shown in chart 1.1, the LNG projects now have higher expectations of the quantity of gas required to meet their long-term LNG contractual commitments in 2019 (an increase from 1262 PJ to 1281 PJ). This is predominantly due to one LNG project revising down maintenance time and expecting to deliver an additional quantity of LNG under its export

²² Jemena, *Northern Gas Pipeline: Draft Environmental Impact Statement*, August 2016, <https://jemena.com.au/documents/pipeline/negi/chapters/1-introduction>.

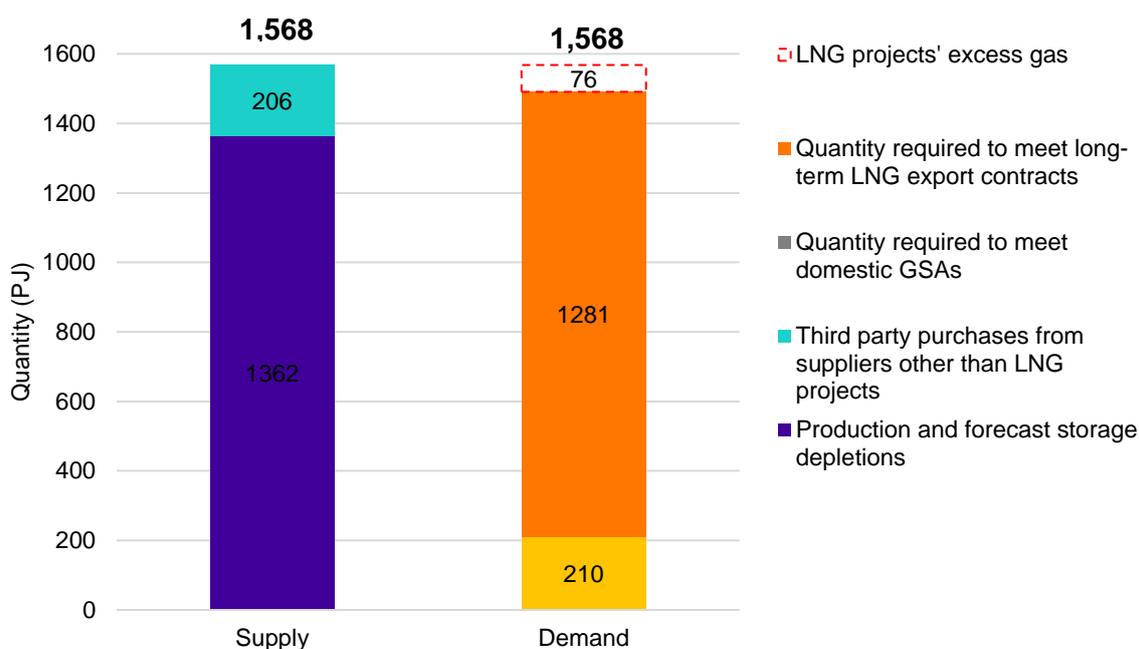
contract.²³ The LNG projects currently have no firm expectations of how much gas they will sell on the international spot markets.

Taking into account their domestic and long-term export GSA requirements (discussed further in section 1.3), the LNG projects currently forecast to have 76 PJ of excess gas available in 2019 (a decrease from 98 PJ). This could be used for either export or to supply the domestic market. However, in keeping with the Heads of Agreement, the LNG projects have committed to first offer this uncontracted gas to the domestic market on competitive market terms before offering it overseas. Should the need arise, the domestic market can therefore expect to have priority over this excess gas. The excess gas will likely act as a buffer for the domestic market if forecast production levels are not met or if actual demand is higher than forecast.

1.3. The LNG projects are forecast to have enough gas to meet their commitments to the domestic and export markets in 2019

Chart 1.2 presents the updated supply and demand balance of the LNG projects for 2019.

Chart 1.2: Forecast supply-demand balance of the Queensland LNG projects for 2019



Source: ACCC analysis of data obtained from the LNG projects as at August 2018.

Note: totals may not add up due to rounding. The increases in the total quantity of third party gas and total quantity of gas required to meet domestic GSAs from the July 2018 report reflects new information received by the ACCC, rather than new purchases or new gas sales, respectively.

Consistent with the ACCC's July 2018 report, chart 1.2 shows that the LNG projects are likely to have sufficient gas available to meet their domestic and LNG contractual commitments in 2019.

²³ This is pursuant to existing clauses in contracts agreed to before the projects were constructed, where buyers are able to alter their annual required quantities.

However, since we reported in July, the LNG projects have revised the quantity of gas that they expect to require in 2019 to meet their long-term export GSAs up by 19 PJ (an increase from 1262 PJ to 1281 PJ). This increase highlights the potential for the quantity of LNG that the LNG projects are required to supply under their long-term export contracts to vary from year to year.

As chart 1.2 shows, the LNG projects, in aggregate, expect to contribute more to the domestic market (210 PJ) than they expect to take out (206 PJ). In the period between April and August 2018, the LNG projects did not enter into any new domestic gas supply agreements for 2019. However, they did continue to contract for domestic supply in 2018 (an increase from 305 PJ to 314 PJ). We expect further contracting for 2019 supply to occur over the remainder of this year and into 2019.

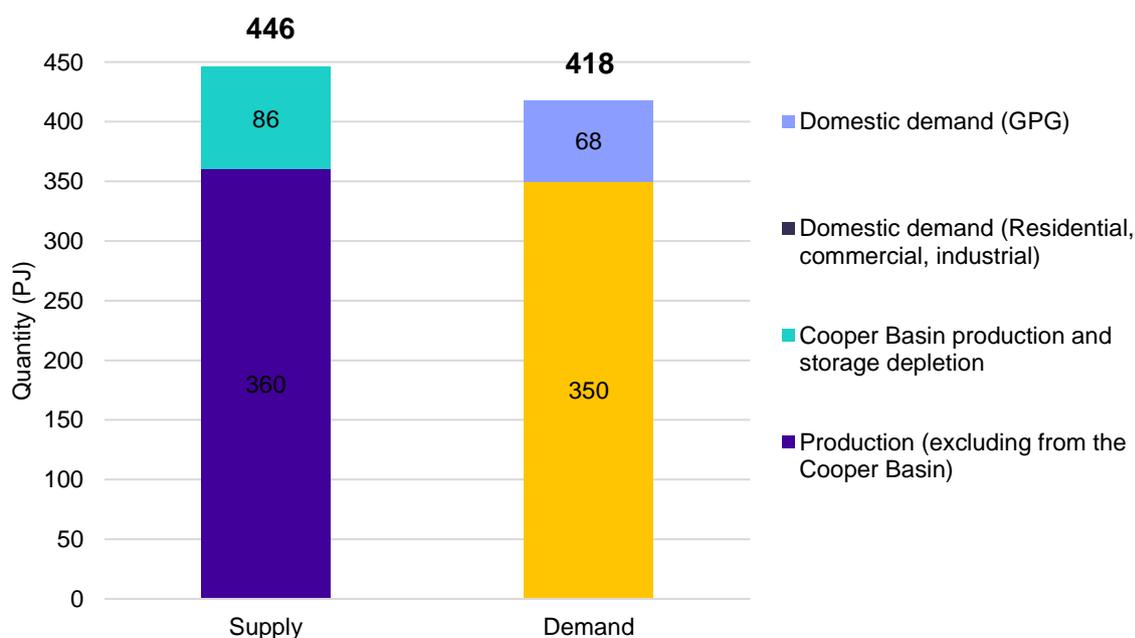
The LNG projects currently forecast 76 PJ of gas available in excess of their domestic and contractual commitments that can be used for either export or to support the east coast domestic market. In line with their commitments to the Australian Government, this uncontracted gas must first be offered to the domestic market on competitive terms before it is offered to the international market.

1.4. The supply-demand balance in the Southern States for 2019 continues to be tight

The overall supply and demand balance in the Southern States for 2019 (presented in chart 1.3 below) remains largely unchanged from what we reported in July 2018.

Forecast supply is based on data obtained directly from producers by the ACCC. Domestic demand is based on AEMO forecasts from its June 2018 Gas Statement of Opportunities (GSOO) and is the same as what was used in the July 2018 report.

Chart 1.3: Forecast domestic supply-demand balance in the Southern States for 2019 (including a portion of Cooper Basin gas)



Source: ACCC analysis of data obtained from gas producers as at August 2018 and of domestic demand data from AEMO's June 2018 GSOO.

As chart 1.3 shows, the supply and demand outlook for the Southern States remains tight. Whether supply is sufficient to meet demand will depend on the level of realised production and Gas Powered Generation (GPG) demand.

Forecast production in the Southern States (excluding the Cooper Basin) has decreased from 370 PJ (as reported in July 2018) to 360 PJ. This is largely a result of reduced gas production forecast by key suppliers in the Gippsland and Otway Basins, including some undeveloped gas production²⁴ being delayed until 2020.

The decrease in forecast production in the Southern States has been somewhat offset by an increase in forecast supply from the Cooper Basin (which includes forecast gas production and storage depletions). 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 2019, taking into account swap agreements. As previously reported by the ACCC, the bulk of Cooper Basin production is contractually committed to the LNG projects in Queensland. While the Cooper Basin is expected to contribute these additional quantities to the Southern States in 2019, this may not be the case for future years.

Another portion of the Cooper Basin gas that the ACCC has included in the supply forecast relates to gas acquired by a gas retailer, which contributes to its overall portfolio. Where the retailer will deliver this gas will ultimately depend on the demand dynamics of the retailer's portfolio at the time. As the retailer could end up delivering some of this gas into Queensland, total supply of 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. GPG demand is highly volatile because it is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, renewable generation investment and unexpected retirement of generation or unplanned outages). If GPG demand is greater than expected, this could shift the supply-demand balance and result in an even tighter market.²⁵

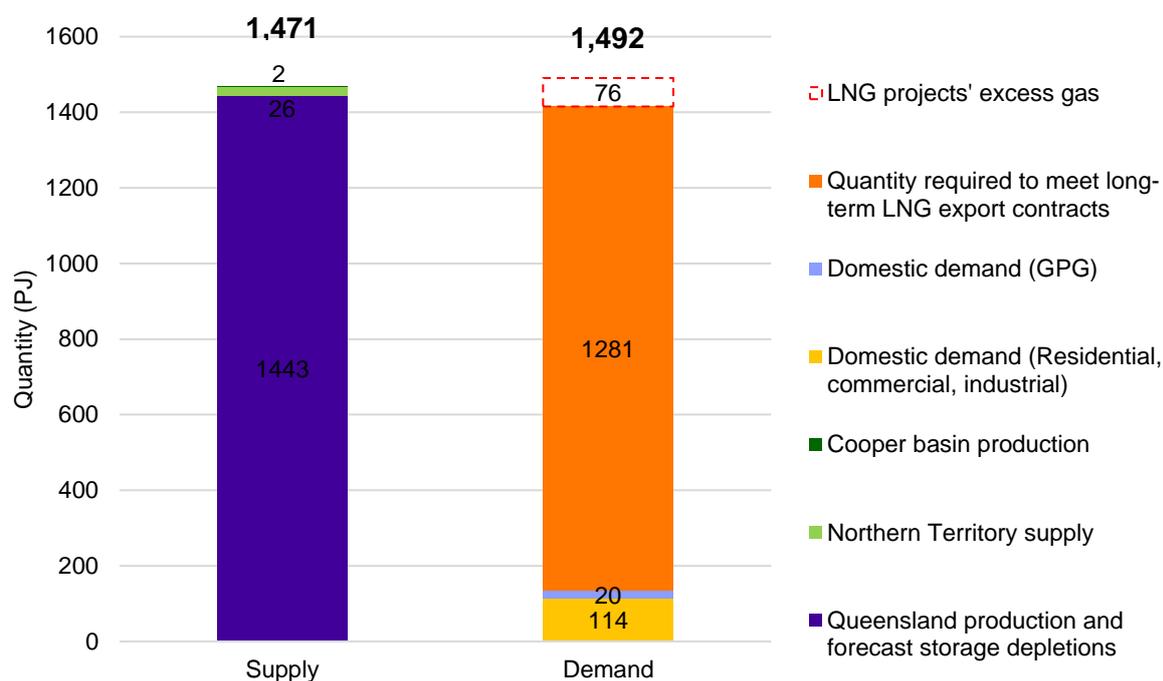
1.5. Queensland is likely to have sufficient gas to meet its needs in 2019

Chart 1.4 updates the supply and demand outlook for Queensland in 2019. Forecast supply is comprised of Queensland's total production plus forecast storage depletions; expected supply from the Northern Territory (which will be connected to Mt Isa once commissioning of the NGP is complete); and a proportion of gas from the Cooper Basin (based on producers' delivery expectations and taking into account gas swaps). Forecast demand is made up of AEMO's neutral domestic demand forecast for Queensland from its June 2018 GSOO (unchanged since the July 2018 report). Forecast export demand is based on data provided directly by the LNG projects to the ACCC.

²⁴ Gas production expected to be recovered through new wells (the performance of which is not yet known) and which may require approval of additional investments before production can commence.

²⁵ The ACCC notes that if GPG does exceed demand expectations and there is insufficient gas on a day to meet peak demands in the National Electricity Market, then the Gas Supply Guarantee may apply.

Chart 1.4: Forecast supply-demand balance in Queensland for 2019



Source: ACCC analysis of data obtained from gas producers as at August 2018 and of domestic demand data from AEMO's June 2018 GSOO.

Note: Totals may not add up due to rounding.

Chart 1.4 shows that, consistent with what was reported in the July 2018 report, Queensland is likely to have sufficient gas available to meet both domestic and contracted LNG export demand in 2019. However, Queensland's supply-demand balance will tighten if the majority of the LNG projects' excess gas is used to supply export markets.

Forecast supply has decreased by 15 PJ from 1486 PJ (as reported in July) to 1471 PJ. This is largely attributable to reductions in the quantity of gas forecast to be produced by some producers in 2019 as well as lower quantities of gas forecast to be withdrawn from storage facilities.

Based on current firm gas supply commitments, about 26 PJ of gas is forecast to flow into Queensland from the Northern Territory in 2019. As the NGP's annual capacity is around 35 PJ, there is potential for additional quantities of Northern Territory gas to flow into Queensland next year.

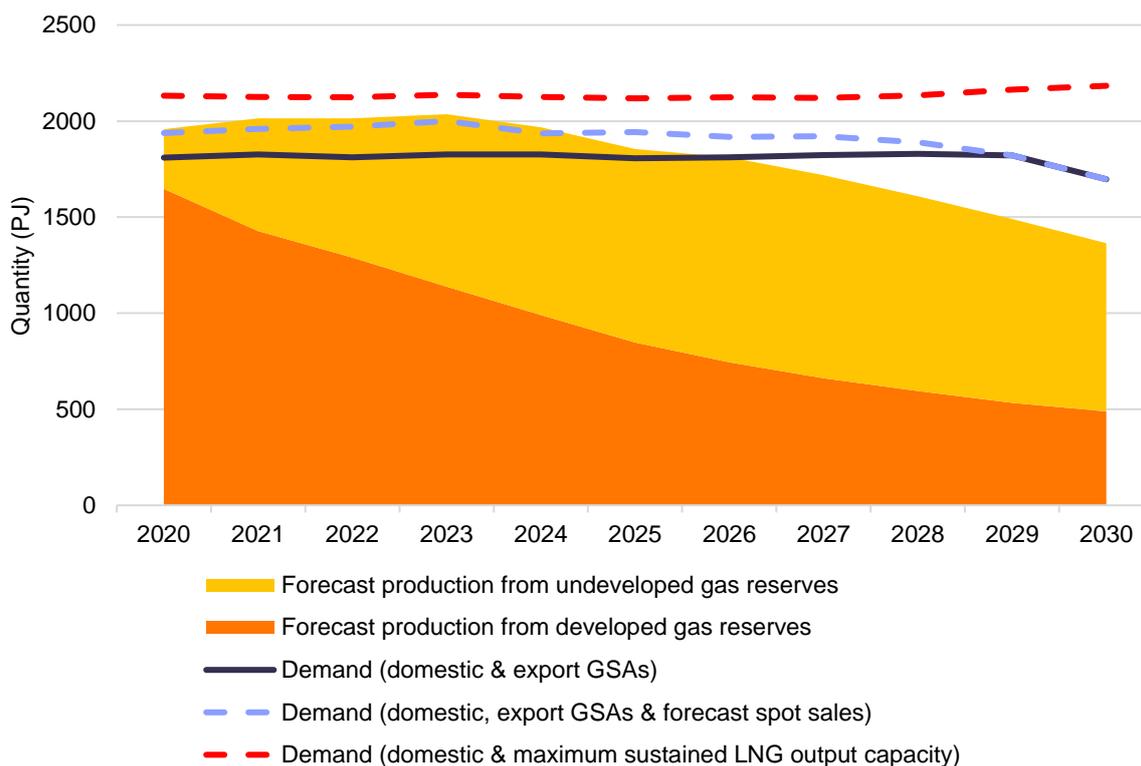
1.6. The long-term supply outlook for the East Coast Gas Market remains uncertain

In December 2017, the ACCC reported on the expected supply and demand balance in the East Coast Gas Market for the ten-year period 2020–2030. The outlook showed a tight market, with future supply and demand uncertain.

Chart 1.5 shows the updated supply and demand outlook for the East Coast Gas Market over the same period. The production forecast only includes production from 2P reserves²⁶ and does not include production from contingent or undiscovered resources (which is presented separately in chart 1.6).

Forecast production and LNG export demand is based on data obtained directly from producers. Domestic demand is based on AEMO's neutral demand scenario from its June 2018 GSOO.²⁷

Chart 1.5: Forecast gas supply (including from the Northern Territory) compared to forecast gas demand, East Coast Gas Market, 2020–2030



Source: ACCC analysis of data obtained from gas producers as at August 2018 and of domestic demand data from AEMO's June 2018 GSOO.

Note: Export demand includes expected feed gas requirements. There are currently no forecast LNG spot sales for years 2029 and 2030.

Chart 1.5 shows that the long-term supply and demand outlook remains tight and uncertain. While current projections indicate enough supply to meet demand in the near- to medium-term, whether supply is sufficient to meet demand will ultimately depend on the actual level of production and demand that is realised.

While the majority of forecast gas production in early years relates to developed gas production or gas production expected to be recovered through existing wells, over time, undeveloped gas production will be increasingly relied on. Undeveloped gas production is less certain than developed gas production as gas is expected to be recovered from new wells – the performance of which is not yet known – and is likely to require approval of

²⁶ 2P reserves are reserves that, based on analysis of geological and engineering data, are more likely than not to be recoverable. That is, where there is at least a 50 per cent probability that the quantity of gas actually recovered will equal or exceed the estimated quantity.

²⁷ Australian Energy Market Operator, *2018 Gas Statement of Opportunities*, June 2018, <https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities>.

additional investments before production can commence. The ultimate timing of production of this gas will therefore depend on whether it is economic to invest in the development of these areas when it is required.

The performance of the coal seam gas fields in Queensland, which are expected to dominate a large proportion of future gas production, remains uncertain. As noted in the December 2017 report, coal seam gas fields require more wells to maintain production than conventional gas fields and have higher associated infrastructure and operating costs.²⁸ The need for continual investment in coal seam gas infrastructure creates ongoing commercial and technical uncertainty over the exact timing and quantity of future gas production from these unconventional reserves.

The ACCC, through its reserves and resources work program (discussed further in section 2.7), has sought to identify the degree of uncertainty associated with current coal seam gas reserves. As those results indicate, 42 per cent of Queensland's coal seam gas reserves relate to areas with existing facilities where gas production is relatively certain, with the other 58 per cent relating to less certain areas that require new infrastructure or substantial investments prior to development.

Chart 1.5 takes into account gas expected to flow to the east coast from the Northern Territory (which will soon be linked to the east coast via the NGP), based on firm gas supply agreements. The NGP's initial capacity will be 35 PJ per annum, but in the future it could increase to up to 256 PJ per annum if Jemena's plans to extend and expand the pipeline proceed.²⁹ As the NGP is not yet fully contracted, there is scope for additional quantities of Northern Territory gas to supply the East Coast Gas Market over the outlook period.

In September 2018, the Northern Territory Government released the Northern Territory Gas Strategy, which is designed to achieve its vision of the Northern Territory as "a world class hub for gas production, manufacturing and services by 2030."³⁰ One of the strategy's five targets is to contribute to national energy security on the east coast. This may result in further quantities of gas from the Northern Territory being made available to the east coast.

There have also been a number of other recent market developments that may affect future supply. These are outlined in box 1.1 below.

²⁸ ACCC, *Gas Inquiry 2017-2020 Interim report*, December 2017, p. 79.

²⁹ Jemena, *Jemena welcomes decision to lift fracking moratorium*, April 2018, <http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori>.

³⁰ Gunner, M (Northern Territory Chief Minister), *Creating local jobs – NT gas strategy revealed*, media release, Northern Territory Government, 5 September 2018.

Box 1.1: Recent market developments

- On 10 October 2018, Shell announced it will progressively drill 250 new gas wells during 2019 and 2020 as part of its QGC venture.³¹ The wells will connect to existing QGC gas processing plants and will bring approximately 930 petajoules of gas to the market over the next three decades. The Queensland Government said QGC will start pre-construction and site preparation activities at some sites in November, with wells to start being drilled from January 2019 through to December 2019, subject to government approvals.³²
- On 25 October 2018, the South Australian Parliament agreed to legislate a 10-year moratorium on hydraulic fracturing in the south-east of South Australia.³³ The Minister for Energy and Mining has stated that this will have “no practical impact upon what may happen with regard to petroleum exploration or production in the South-East”.³⁴
- On 29 October 2018, Senex Energy announced that it would be investing more than \$200 million into developing two natural gas projects in the Surat Basin: Project Atlas and Roma North.³⁵ Senex will drill an initial 110 wells over 18 months beginning in 2019. Project Atlas is expected to deliver 200 PJ of gas over the life of the project.
- On 2 November 2018, the Queensland Government released more than 6600 square kilometres of land for gas exploration, with more than 900 square kilometres reserved for domestic supply only.³⁶ A further 18 square kilometres was released on 15 November 2018, exclusively for domestic supply to local manufacturers.³⁷ On 15 November 2018, Santos announced that its 50–50 joint venture with Shell won approximately 400 square kilometres of Queensland acreage reserved for domestic use.³⁸
- On 5 November 2018, APLNG announced that it had reached an infrastructure sharing agreement with the QCLNG project, with APLNG also taking up the opportunity to secure additional gas.³⁹ Under the agreement, the QCLNG project will be able to transport and process gas from the Arrow Energy Surat Basin fields using available capacity in existing APLNG-QCLNG joint infrastructure. In addition, APLNG will buy up to an additional 350 PJ of gas from the QCLNG project. The gas will be bought at an oil-linked price over 10 years from 2024.⁴⁰ The arrangements are subject to Arrow Energy making certain final investment decisions in relation to the development of its Surat Basin fields.

On the demand side, domestic demand forecasts have varied greatly over the last two years, reflecting uncertainty about the role of gas in electricity generation. Compared to AEMO’s previous long-term forecast of domestic demand (which was used by the ACCC in its December 2017 report), projected domestic gas demand in the near term is expected to be considerably lower. This is primarily due to higher forecast levels of renewable generation in the National Electricity Market and lower forecast demand for gas from GPG.

³¹ Shell, Shell’s QGC venture set to develop more natural gas, media release, 10 October 2018.

³² Lynham, A (Minister for Natural Resources, Mines and Energy), Gas fires new jobs, contracts for Western Downs, media release, Queensland Government, 10 October 2018.

³³ Petroleum and Geothermal Energy (Ban on Hydraulic Fracturing) Amendment Bill 2018 (SA).

³⁴ South Australia, Parliamentary Debates, House of Assembly, 5 September 2018, p. 2265 (Hon. D.C. Van Holst Pellekaan, Minister for Energy and Mining).

³⁵ Senex Energy, Senex reaches milestone towards domestic gas delivery, media release, 29 October 2018.

³⁶ Lynham, A (Minister for Natural Resources, Mines and Energy), Queensland continues to fuel the nation, media statement, Queensland Government, 2 November 2018.

³⁷ Department of Natural Resources and Mines, *Call for tenders for authorities to prospect, petroleum and gas – Surat Basin (PLR2018-1B)*, Queensland Government, 15 November 2018, <https://www.hpw.qld.gov.au/qtenders/tender/display/tender-details.do?CSRFNONCE=9FCDBF12D935F8CEEC667FD14076D9A1&id=26101>.

³⁸ Santos, Santos Shell JV wins new Queensland domestic gas acreage, media release, 15 November 2018, <https://www.santos.com/media-centre/announcements/santos-shell-jv-wins-new-queensland-domestic-gas-acreage/>.

³⁹ APLNG, ‘Australia Pacific LNG to share infrastructure and secure additional gas supply to diversify portfolio’, media release, 5 November 2018.

⁴⁰ *ibid.*

From 2025, AEMO projects GPG demand will be higher than in the preceding years, however, it does not expect it to recover to historically observed levels of greater than 200 PJ.⁴¹ Given the highly uncertain nature of GPG demand, actual domestic demand may differ to that reflected in chart 1.5. This needs to be taken into account when assessing whether forecast supply is likely to be sufficient to meet future demand expectations.

Given the current supply outlook, the degree to which production from 2P reserves is likely to meet demand will depend on the extent to which the LNG projects engage in LNG spot sales. As shown in the chart above, while the LNG projects forecast to engage in some spot sales, they are not currently expecting to utilise their LNG trains' maximum sustained LNG output capacity.⁴²

The LNG projects currently anticipate using around 80 per cent of their LNG trains' maximum sustained LNG output capacity to meet their long-term export GSAs over the outlook period. If they were to fully utilise their maximum sustained LNG output capacity, the LNG projects could sell up to an additional 3600 PJ⁴³ of LNG on the export markets in the period 2020–2030. The LNG projects currently expect to sell about 1100 PJ on the LNG spot markets in this period, which means that they currently expect to have enough spare capacity to sell up to 2500 PJ of LNG on top of this.

If international LNG spot prices remain high or increase even further, the LNG projects are likely to have a strong commercial incentive to maximise the use of spare capacity in their LNG trains. If they decide to export additional gas, this will affect the availability of gas for the domestic market unless there is a corresponding increase in gas production.

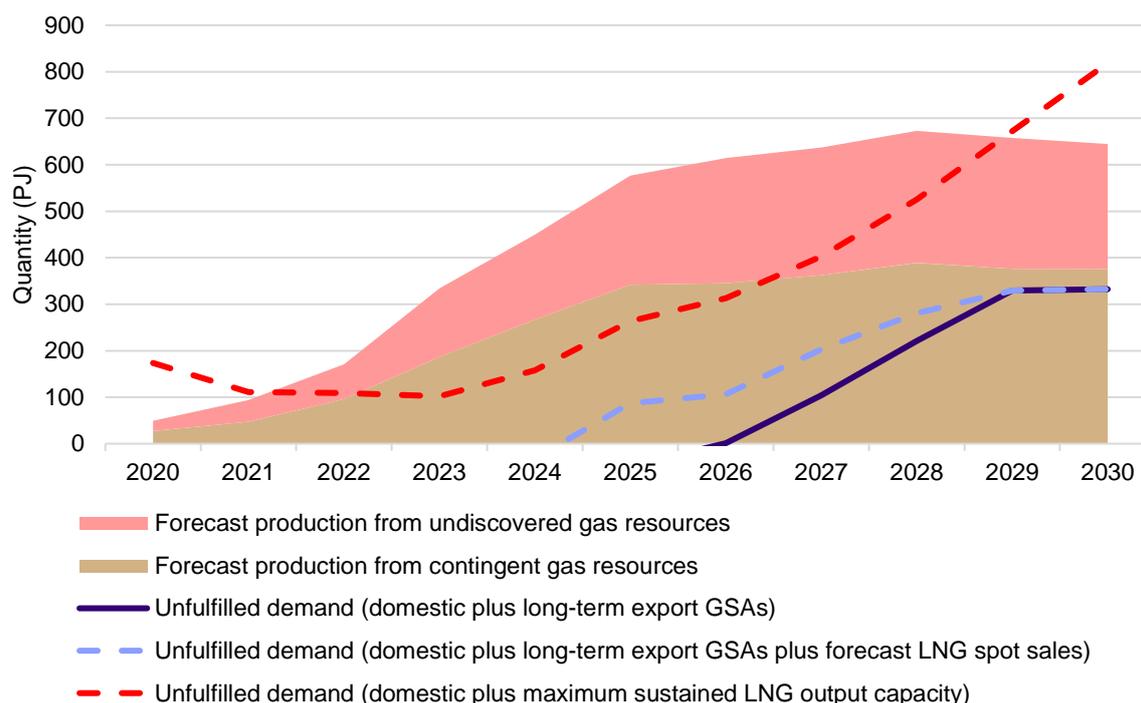
Chart 1.6 assumes that the production in chart 1.5 will be realised and shows potential gas production from contingent and undiscovered resources against the remaining unfulfilled demand (that is, the difference between demand and production from 2P reserves, as presented in chart 1.5).

⁴¹ Australian Energy Market Operator, *2018 Statement of Opportunities*, June 2018, p. 4.

⁴² That is, the maximum quantity of LNG the LNG trains are capable of producing on a sustained basis over the course of a year, taking into account required maintenance.

⁴³ This figure includes feed gas requirements (such as fuel) required to produce the LNG.

Chart 1.6: Unfulfilled demand and forecast production from contingent and undiscovered gas resources, East Coast Gas Market, 2020–2030



Source: ACCC analysis of data obtained from gas producers as at August 2018 and of domestic demand data from AEMO's June 2018 GSOO.

Note: there are currently no forecast LNG spot sales for years 2029 and 2030.

Chart 1.6 shows that forecast production from contingent and undiscovered gas resources, if realised, could alleviate most of the potential supply gaps over the outlook period. However, there can be significant challenges to their development, so the exact timing and likely quantities of production from contingent and undiscovered gas resources are highly uncertain.

Contingent gas resources are more challenging and more technically difficult to extract than 2P reserves. As such, they may require construction of additional infrastructure (such as treatment or conditioning facilities and/or pipelines) to support the development process. Further, the majority of contingent gas resources are in fields that have yet to be approved for development (see section 2.4). This means necessary approvals may also need to be obtained before development can commence.

For the purpose of chart 1.6, undiscovered gas resources are defined as those gas resources that are estimated to be potentially recoverable but that have not yet been proven by drilling. Production estimates from these gas resources are even more uncertain than from contingent gas resources, as greater testing and investment is required before any production can occur.

While successful production from contingent and undiscovered gas resources would contribute material additional quantities of gas into the market, whether production proceeds will ultimately depend on the economics of exploration and development.

In addition to locally-sourced gas, an option to provide additional supply in the relatively near future is through an LNG import terminal on the east coast. There are currently four entities considering the development of LNG import facilities on Australia's east coast: Australian Industrial Energy, AGL, Venice Energy (a wholly owned subsidiary of IG Partners) and

ExxonMobil. These parties are considering importing LNG into the east coast through floating storage and regasification units (FSRU), which convert LNG to its gaseous state.

The ACCC understands that the capacity of these import terminals could range from about 100 PJ to 120 PJ, but the terminals may not utilise all of their capacity, particularly in the first few years of operation. Prices for gas from these projects are likely to be broadly consistent with market prices for gas. More information on these projects is provided in the table below.

Table 1.1: Comparison of proposed LNG import terminal projects

Operator		Australian Industrial Energy	AGL	ExxonMobil	Venice Energy
Location		Port Kembla ⁴⁴ New South Wales (approximately 100km south of Sydney)	Crib Point, Western Port Bay ⁴⁵ Victoria (approximately 80km south-east of Melbourne)	Western Port or Offshore Bass Strait Location Victoria	Outer Harbor ⁴⁶ South Australia (approximately 20km north-west of Adelaide)
Proposed Commencement		2020	2021 ⁴⁷	2022 ⁴⁸	2022
Associated Infrastructure	Import terminal	Floating storage and regasification unit (FSRU) ⁴⁹	FSRU ⁵⁰	FSRU	FSRU ⁵¹
	Wharf	Redevelopment of existing berth	Upgrade of existing jetty	Options being considered	Construction of a new wharf
	Pipeline	12 km pipeline from the wharf to Jemena's Eastern Gas Pipeline comprised of an expansion of the existing spur line and new works.	55 km bi-directional pipeline from the import jetty to APA's Victorian Transmission System near Pakenham ⁵²	Options being considered	Connection to the Moomba to Adelaide Pipeline System
Demand Facilities proposed by proponents		Potential for a 700MW Combine cycle gas turbine (CCGT) Power Station	n/a	n/a	500MW Open Cycle Gas Turbine (OCGT) Power Station

⁴⁴ Australian Industrial Energy, *Our Project*, 2018, <https://ausindenergy.com/our-project/>.

⁴⁵ AGL, *AGL Gas Import Jetty Project*, <https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project>.

On 9 October 2018, the Hon. Richard Wynne MP, Victorian Minister for Planning, announced that the project will be subject to an Environmental Effects Statement to examine the environmental impacts of the import facility and the adjoining pipeline.

⁴⁶ Venice Energy, *Outer Harbor Power Project*, 2018, <https://veniceenergy.com/outer-harbor-power-project/>.

⁴⁷ AGL, AGL reaches key milestones for proposed LNG import jetty, media release, 12 June 2018.

⁴⁸ As at July 2018.

⁴⁹ Australian Industrial Energy, *Our Project*, 2018, <https://ausindenergy.com/our-project/>.

⁵⁰ AGL, *AGL Gas Import Jetty Project*, <https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project>.

⁵¹ Venice Energy, *Outer Harbor Power Project*, 2018, <https://veniceenergy.com/outer-harbor-power-project/>.

⁵² AGL, *Crib Point Project*, <https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project>.

If one or more of these projects is built, this will create an option to bring additional quantities of gas into the East Coast Gas Market. While this may act as an additional safety net and reduce the likelihood of a shortfall on the east coast, imported LNG is unlikely to be a source of lower priced gas.

2. Upstream activities

2.1. Key points

- The East Coast Gas Market is heavily reliant on gas from Queensland. Over 80 per cent of 2P reserves and almost 65 per cent of 2C resources in the east coast are located in Queensland and controlled by the LNG producers, either through ownership or through purchases from other suppliers.
- Gas reserves in the Southern States are in decline. If the Gippsland Basin Joint Venture (GBJV) – the largest gas supplier in the Southern States – was the sole supplier, its 2P reserves (2436 PJ) would only be sufficient to meet expected domestic demand in the Southern States for around 6 years.
- This means that in the medium to longer-term, the Southern States will need to develop new sources of gas, transport more from Queensland or import gas from overseas. Further investment in pipeline and/or storage capacity may be required to enable more gas to flow from Queensland into the Southern States.
- The ACCC previously reported that Esso's offshore Dory gas field in Bass Strait had the potential to contain a significant quantity of gas. However, in 2018, Esso drilled two exploration wells to test Dory and was not able to find commercial quantities of gas.
- Very little additional exploration is planned in offshore Victoria in the next three years and no onshore exploration is expected in NSW or Victoria due to the regulatory settings in those states.
- In the Bowen, Surat and Cooper basins, exploration and appraisal activities are forecast to increase over the next three years, after falling to a very low level in 2016. However, the number of exploration wells expected to be drilled in 2019 is 40 per cent lower than in 2013.
- There are still substantial uncontracted 2P reserves in the east coast. However, the bulk of these are in CSG fields controlled by the LNG producers in Queensland. The timing of the development of these reserves will depend on a number of factors, including the performance of the CSG wells, production costs, gas prices and, critically, choices made by the LNG producers on how much gas to supply into the domestic and export markets.
- Uncertainty about the long-term performance of CSG fields remains. In the period 30 June 2017 to 30 June 2018, 2P reserves in the east coast fell by 4994 PJ. This is largely attributable to substantial write-downs of CSG reserves in Queensland, particularly in Arrow-operated fields.
- Inconsistent reporting of reserves and resources, and the lack of transparency surrounding gas price assumptions underpinning reserve and resource estimates, continue to inhibit informed decision making of market participants. Material variances in the gas price assumptions used by producers to estimate their reserves make it difficult for market participants to compare reserve estimates and accurately assess future gas supply. The ACCC will develop and consult on a proposed reporting framework for the consistent reporting of reserves and resources in early 2019.
- The high level of international LNG prices and the significant increase in east coast gas demand driven by the LNG producers over recent years have accelerated the development of gas reserves across the east coast, causing lower-cost gas from conventional reserves to become depleted at a faster rate than it otherwise would have.
- As a result, production costs across the east coast are rising. Core Energy estimates that the lifecycle costs of conventional gas developments that have begun production in

recent years or are yet to commence are between \$5.40/GJ and \$8.25/GJ.⁵³ Core Energy estimates that the lifecycle costs of almost all CSG reserves range between \$6.35/GJ and \$6.80/GJ.

2.2. Introduction

In the 2015 Inquiry, the ACCC found that the East Coast Gas Market was not signalling expected supply problems effectively because information on reserves and resources and other upstream activities in the east coast was fragmented and reported on an inconsistent basis.⁵⁴ The ACCC therefore recommended that steps be taken to improve the transparency of upstream activities and the consistency of reporting by producers.⁵⁵

In keeping with this recommendation, the ACCC has, as part of the current Inquiry, sought information from each producer on their current holdings of reserves and resources, as well as exploration activities. The ACCC has also engaged a consultant to develop production cost estimates to better understand the costs currently faced by producers in producing gas.

Sections 2.3 to 2.7 of this chapter discuss the reserves and resources information that was obtained by the ACCC (outlined in box 2.1 below).

Sections 2.8 to 2.9 discuss the information received by the ACCC on exploration activities, while section 2.10 discusses the production cost estimates.

⁵³ The ACCC engaged Core Energy to develop production cost estimates for 2P reserves in the east coast.

⁵⁴ ACCC, Inquiry into the east coast gas market, April 2016, p. 82.

⁵⁵ *ibid.*

Box 2.1: Reporting framework for reserves and resources

The ACCC sought information on reserves and resources from producers based on the Society of Petroleum Engineers' Petroleum Resources Management System (PRMS).⁵⁶ PRMS is a widely used principles-based reporting standard that provides for a consistent approach to the calculation of petroleum quantities. The ACCC also drew on elements of the ASX Listing Rules and the reporting frameworks used internationally. A summary of the information the ACCC requested is set out in the table below.

Summary of information request

Type of information	Information requested		
Reserves	1P (proved reserves) Have at least a 90% probability that the quantities recovered will equal or exceed the estimate	2P (proved plus probable reserves) Have at least a 50% probability that the quantities recovered will equal or exceed the estimate	3P (proved plus probable plus possible) Have at least a 10% probability that the quantities recovered will equal or exceed the estimate
	Broken down into developed ⁵⁷ and undeveloped ⁵⁸ reserves		
Resources	1C Low estimate of contingent resources	2C Best estimate of contingent resources	
Movements in 2P Reserves over the last 12 months	Movements in reserves over the last 12 months broken down into: production, discoveries, acquisitions, divestments, extensions ⁵⁹ and other revisions		
Reporting	Sales quantities of gas (i.e. not including fuel gas) ⁶⁰ from all gas-containing fields in petajoules (PJ) on a net revenue interest basis (i.e. after royalties and production sharing contracts).		

When a gas reservoir is discovered, it is classified as either a reserve or resource, depending on its commerciality. Reserves are those quantities of gas that are expected to be commercially recoverable. Contingent resources, on other hand, are those quantities estimated to be potentially recoverable but not yet commercial to develop, due to one or more contingencies (i.e. there is currently no viable market, or the commercial recovery depends on the development of technology or infrastructure).⁶¹

Within each category of reserves and resources there are different confidence levels (for example, reserves may be categorised as proved, probable or possible). These classifications indicate how confident producers are that they will be able to extract the relevant quantities of gas from known reservoirs.

To understand the range of potential recovery outcomes in the east coast, the ACCC sought information from producers on their best estimate of 1P, 2P and 3P reserves, as well as 1C and 2C

⁵⁶ Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, revised June 2018.

⁵⁷ Quantities expected to be recovered from existing wells and facilities.

⁵⁸ Quantities expected to be recovered through future significant investments.

⁵⁹ Changes to the prior year's 2P reserves in a field resulting from the enlargement of its proved area.

⁶⁰ Note this is different to the way data is collected by the Department of Natural Resources, Mines and Energy.

⁶¹ Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, revised June 2018, p. 3.

resources as at 30 June 2018. The information on reserves was requested on a “developed” and “undeveloped” basis to better understand the different risk profiles associated with the reserves.⁶²

The ACCC also sought information on:

- the change in 2P reserves that occurred over the period 30 June 2017 to 30 June 2018 as a result of production, discoveries, extensions, acquisitions, divestments and other revisions
- the gas price assumptions used by suppliers when assessing a project’s commerciality, which is a critical component in the estimation of reserves.

The ACCC requested this information at a field level and asked producers to indicate whether each field was:

- currently producing, approved for development but yet to produce,⁶³ or at another stage of development⁶⁴
- a conventional gas field, coal seam gas field, or other type of unconventional gas field⁶⁵
- a dry gas field (mostly methane), gas condensate field (mainly condensates or liquid hydrocarbons) or an oil field (where gas is found associated with oil).⁶⁶

The data collected from producers reflects sales quantities (i.e. quantities available for sale excluding those quantities consumed in operations, flared or lost in operations) and is based on their net revenue interests (a producer’s revenue share of gas sales after deduction of royalties and share of production owing to others under applicable lease and fiscal terms). The unit of measurement used is petajoules (PJ).

The ACCC will use the information obtained from producers to develop a reporting framework for future reporting of reserves and resources. The ACCC intends to consult with interested parties on the proposed reporting framework in early 2019. As part of this process, the ACCC also intends to consult on the recommendation contained in the 2015 Inquiry, regarding the use of common price assumptions for reserves reporting. While the ACCC has obtained some information on the price assumptions currently used by producers (section 2.6), it intends to undertake further work on this issue early next year.

⁶² Undeveloped reserves are less certain than developed reserves because they require significant investment before production can commence.

⁶³ The term ‘approved for development but not yet producing’ was defined as a field for which all necessary approvals have been obtained, capital has been committed and for which development is ready to begin or is under way.

⁶⁴ This information can provide an indication on the likely timing of the development of reserves and resources.

⁶⁵ This information is important because different types of gas require different extraction methods, which gives rise to different risks and costs.

⁶⁶ This information is relevant because different types of gas fields can require different levels of processing to meet sales gas requirements.

2.3. The bulk of reserves and resources in the east coast are held by the LNG producers in Queensland

Table 2.1 shows the current level of reserves (1P, 2P and 3P) and resources (1C and 2C) in the East Coast Gas Market, by basin, based on information provided by producers to the ACCC. The table also provides a breakdown of reserves by gas type (coal seam gas, conventional natural gas or other).

Table 2.1: Quantity of reserves and resources in the East Coast Gas Market as at 30 June 2018 (PJ)

	Reserves			Contingent Resources	
	1P	2P	3P	1C	2C
Bowen/Surat Basins	14 376	33 848	37 875	3 685	21 927
Gippsland Basin	2 152	2 864	3 179	531	1 658
Cooper Basin	478	991	1 780	742	4 022
Otway Basin	344	517	706	21	135
Bass Basin	69	97	126	75	315
Sydney Basin	11	13	16	–	–
Clarence-Moreton Basin	–	80	408	–	588
Gunnedah Basin	–	–	–	1 182	2 060
Galilee Basin	–	–	–	355	2 750
Isa Super Basin	–	–	–	35	164
Total East Coast	17 430	38 411	44 088	6 626	33 619
CSG	14 346	33 873	38 123	5 148	25 249
Conventional natural gas	2 894	4 101	5 153	862	3 139
Other	191	437	813	616	5 231

Source: ACCC analysis of data obtained from gas producers.

Notes: Totals may not add up due to rounding. Estimates of reserves and resources are based on net revenue interests. The category 'other' in the table includes: 'unconventional gas', 'conventional and CSG' and 'conventional and unconventional'.

As table 2.1 shows, there are currently 38 411 PJ of 2P reserves in the east coast, of which 88 per cent are located in Queensland and nine per cent are located in offshore Victoria. With most of the gas currently considered economic to develop located in Queensland, further investments in pipeline and storage capacity may be required in the medium to longer-term to enable more gas to flow from Queensland into the Southern States (see section 4.5).

In a similar manner to 2P reserves, the majority of the 33 619 PJ of 2C resources are located in Queensland, with the Bowen and Surat Basins accounting for the greatest share (65 per cent) followed by the Cooper (12 per cent), Galilee (8 per cent) and Gunnedah (6 per cent) basins. The latter two of these basins are yet to be developed and are not currently connected to the East Coast Gas Market. Further investment in pipeline capacity would therefore be required to bring this gas to market (see section 4.5).

As noted in box 2.1, reserves and resources information can provide different insights into the future supply of gas. Where reserves refer to areas of gas that are commercially viable to develop, contingent resources are not yet considered commercially recoverable. This can be due to a number of reasons – for example, there may be no currently viable market, the necessary technology for production might still be under development, or the evaluation of the accumulation could be insufficient to determine if it can be produced commercially.⁶⁷ So while they are currently considered not commercial to recover, future investments and

⁶⁷ ACCC, *Inquiry into the east coast gas market*, April 2016, p. 160.

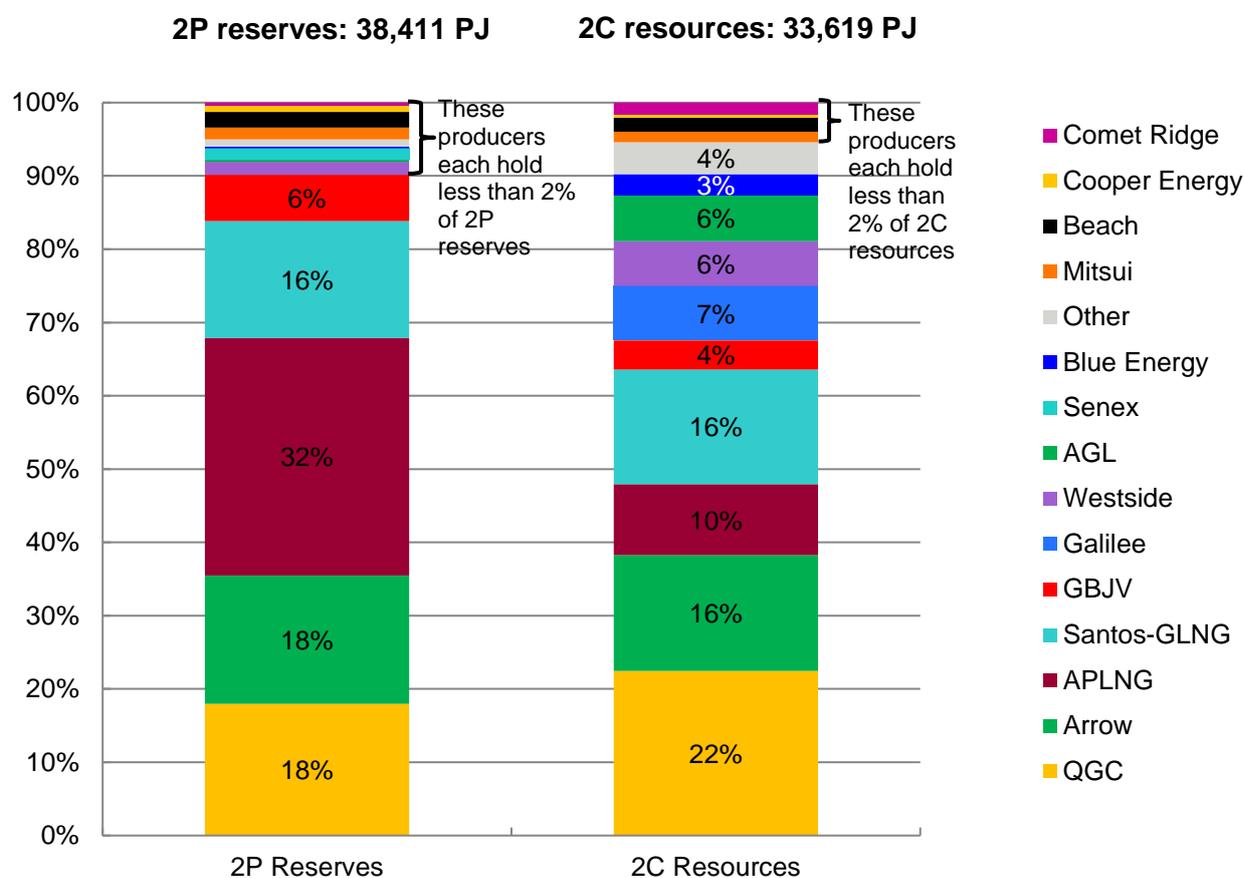
market developments may result in a reclassification of these resources into commercially recoverable reserves.

The various classifications of reserves and resources provide information about the quantity of gas that could be produced in the most certain and less certain recovery scenarios. For example, 1P reserve estimates provide insight into the quantities that are highly likely to be recoverable, whereas 2P and 3P estimates provide insight into the upside of those estimates. As presented in table 2.1, the confidence levels for reserves currently range from 17 430 PJ to 44 088 PJ. For contingent resources, these range from 6626 PJ to 33 619 PJ. According to PRMS, the best estimates of reserves and resources are 2P reserves and 2C resources as these are generally considered to represent the “most realistic assessment of a project’s recoverable quantities”.⁶⁸

Chart 2.1 provides a breakdown of the 2P reserves and 2C resources held by each producer.

⁶⁸ Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, revised June 2018, p. 14.

Chart 2.1: Quantity of 2P reserves and 2C resources held by producers in the East Coast Gas Market as at 30 June 2018



Source: ACCC analysis of data obtained from gas producers.

Notes: Estimates of reserves and resources are based on net revenue interests.

Santos-GLNG's share of 2P reserves and 2C resources include Santos, PETRONAS, KOGAS and Total's interests in the GLNG Joint Venture Project, as well as Santos's non-GLNG interests.

Mitsui's share of 2P reserves and 2C resources include its interests in AWE and Peedamullah.

QGC's share of 2P reserves and 2C resources include Tokyo Gas and CNOOC's interests in the QCLNG project.

GBJV's share of 2P reserves and 2C resources include its interests in the Kipper Unit Joint Venture.

AGL's share of 2P reserves and 2C resources include the interests it holds in both the Moranbah Gas project Joint Venture and the North Queensland Energy Joint Venture and its participation rights in the ATP1103 exploration licence located in the Bowen Basin. While AGL agreed to sell these interests to Order (Moranbah) Holdings Pty Ltd in August 2017, at the time it reported its reserves and resources information to the ACCC, the sale was still subject to a number of conditions precedent, including regulatory approval.

The 'other' category includes Armour Energy, EnergyAustralia, Origin Energy, Real Energy, SGH Energy, Stanwell, Tri-Star, Strike Energy and Vintage Energy.

As chart 2.1 shows, over 80 per cent of 2P reserves are held by the LNG producers in Queensland either through ownership or through purchases from other suppliers. APLNG holds the greatest share (32 per cent), QGC holds the second highest share (18 per cent) and has also acquired the bulk of Arrow Energy's share (18 per cent),⁶⁹ while Santos-GLNG controls the third highest share (16 per cent). In the same way, the LNG producers control close to 65 per cent of 2C resources.

⁶⁹ Arrow Energy is a joint venture between Shell and PetroChina. In December 2017, Arrow agreed to supply the QCLNG project (in which Shell is also a participant) with uncontracted gas from its Surat Basin fields for 27 years: <https://www.arrowenergy.com.au/media-centre/latest-news/pages/2017/arrow-energy-agrees-deal-for-surat-basin-reserves>.

Amongst the other producers, the GBJV accounts for the greatest proportion of 2P reserves (6 per cent), while Galilee Energy accounts for the greatest proportion of 2C resources (7 per cent).

While the GBJV is by far the largest producer in the Southern States (responsible for around 80 per cent of production in offshore Victoria in 2017),⁷⁰ it currently only holds 2436 PJ of 2P reserves. Based on expected demand in the Southern States (as forecast by AEMO in its June 2018 GSOO), these reserves alone would be sufficient to only meet demand needs in the Southern States for the next six years.

2.4. The majority of reserves and resources in the east coast are currently undeveloped

Table 2.2 provides some insight into the uncertainty associated with current reserve and resource levels in the east coast.

Table 2.2: Breakdown of reserves and resource levels in the East Coast Gas Market, by stage of development as at 30 June 2018 (PJ)

		Reserves			Contingent Resources	
		1P	2P	3P	1C	2C
Developed Reserves		13 741	17 734	18 661	n.a.	n.a.
Undeveloped Reserves and Resources	Field in production	3 240	14 181	16 452	2 344	9 554
	Approved for development	221	424	487	1	1
	Other	228	6 073	8 488	4 281	24 064
Total		17 430	38 411	44 088	6 626	33 619
Developed % of Total		79%	46%	42%	0%	0%
Undeveloped % of Total		21%	54%	58%	100%	100%

Source: ACCC analysis of data obtained from gas producers.

Note: Totals may not add up due to rounding.

The table shows that over half of the 2P reserves (54 per cent) are currently undeveloped. In contrast to developed reserves, where gas is expected to be recovered from existing wells and facilities, significant investments are likely to be required to recover undeveloped reserves. Production from undeveloped reserves is therefore less certain than production from developed reserves, with the ultimate timing of production from these sources depending on whether it is economic to invest in development when it is required.

While 54 per cent of 2P reserves are undeveloped, it is worth noting that a significant portion of these reserves are located in fields that are currently in production or approved for development. This means that producers have all the necessary approvals and have already made, or committed to making, the investment in infrastructure required for production, with development ready to begin or already under way. There is therefore a greater likelihood that gas from these fields will be produced in the short to medium term.

In contrast to 2P reserves, the majority of 2C resources (72 per cent) are in fields that are not yet in production or approved for development. As mentioned earlier, the barriers to development of contingent resources are greater than reserves and may require significant

⁷⁰ AEMO, *Natural Gas Bulletin Board: Gas Flow*, <https://www.aemo.com.au/Gas/Gas-Bulletin-Board/reports>.

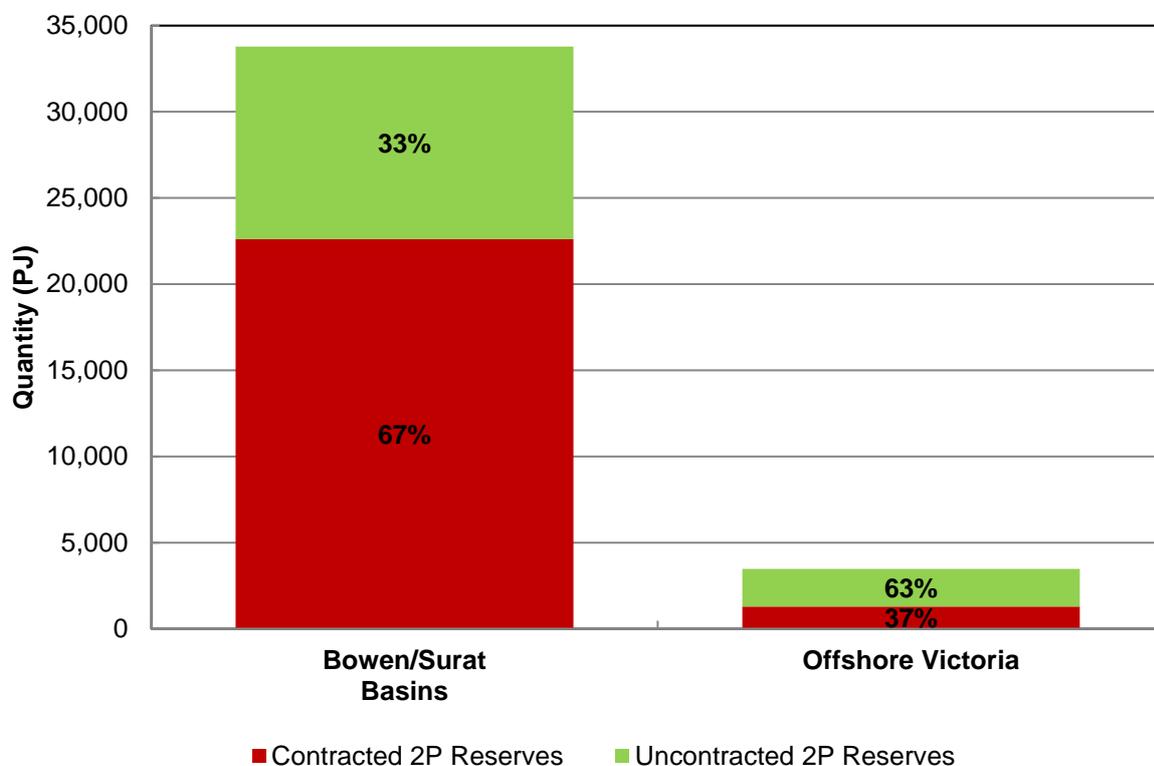
investment in technology or infrastructure to support the development process. The likelihood and timing of production from these resources is therefore highly uncertain.

The development of undeveloped reserves and contingent resources will be increasingly necessary to ensure long-term security of supply as production from developed reserves declines (discussed further in section 1.6) and developed 2P reserves approach depletion. It will also be necessary to meet existing contractual commitments, particularly in the Bowen and Surat basins, as discussed below.

2.5. A significant proportion of reserves and resources in the east coast are already contracted

Chart 2.2 shows the breakdown of contracted and uncontracted 2P reserves in the two largest gas producing areas in the east coast: the Bowen/Surat basins and offshore Victoria.

Chart 2.2: Breakdown of contracted and uncontracted 2P reserves in the Bowen/Surat basins and offshore Victoria as at 30 June 2018



Source: ACCC analysis of data obtained from producers.

Note: Offshore Victoria includes the Bass, Gippsland and Otway Basins.

As this chart shows, on an aggregate basis a significant proportion (64 per cent) of the 38 411 PJ of 2P reserves in these two key gas producing areas have already been contracted, the majority of which are located in the Bowen and Surat basins (67 per cent). While only 33 per cent of the 2P reserves in the Bowen and Surat basins remain uncontracted, this represents a significant quantity of gas (11 242 PJ), particularly when compared to the uncontracted 2P reserves in offshore Victoria (2185 PJ).

While not shown in chart 2.2, the total quantity of 2P reserves that has been contracted under existing GSAs in the east coast is 38 per cent higher than the quantity of developed

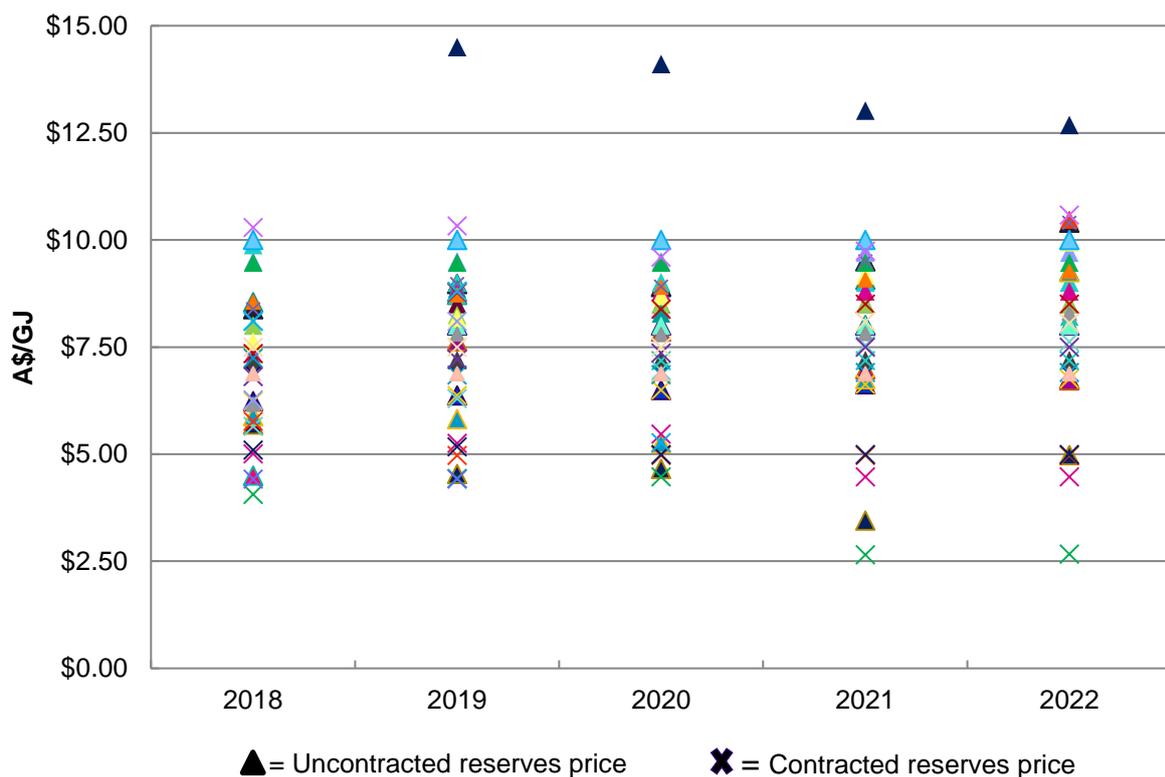
2P reserves. Further development will therefore be required to meet these existing contractual commitments, particularly in the Bowen and Surat basins where the quantity of contracted 2P reserves is 57 per cent higher than the quantity of developed 2P reserves.

It is important to note that while the quantity of contracted 2P reserves in the Bowen and Surat basins exceeds the quantity of developed 2P reserves in these two basins, there appears to be sufficient undeveloped 2P reserves in fields that are currently in production to meet the existing contractual obligations (see table 2.2). Further work will nevertheless be required to develop these reserves.

2.6. There is substantial variance in gas price assumptions underpinning reserve estimates of producers in the east coast

Gas prices are a key determinant of a project’s commerciality. As part of the ACCC’s request for information, producers were asked to provide the gas price assumptions used to assess the commercial viability of their contracted and uncontracted reserves over the period 2018–2022, as well as the basis for these assumptions. These assumptions are summarised in chart 2.3, with separate markers used to identify the assumptions used for contracted reserves and uncontracted reserves.

Chart 2.3: Gas price assumptions underpinning producers’ reserve estimates



Source: ACCC analysis of data obtained from producers.

Chart 2.3 shows that the gas price assumptions varied markedly across producers. For contracted reserves, gas price assumptions ranged from \$2.65/GJ–\$10.58/GJ. Producers typically noted that these assumptions were based on the prices and/or the pricing mechanisms specified in the GSAs for which the reserves had been contracted.

For uncontracted reserves, the gas prices assumptions ranged from \$3.45/GJ–\$14.50/GJ. Producers typically noted that these assumptions were based on an estimate or a forecast of a ‘market-based’ price, determined with reference to a particular point in time, using either:

- oil-linked pricing mechanisms, which are dependent on forecasts of Brent Crude oil or Japanese Crude Cocktail (JCC) prices and exchange rates, or
- domestic price ‘benchmarks’, such as those appearing in AEMO reports, broker reports and other industry reports.

A number of producers also noted that these price assumptions, which are used to assess the commercial viability of reserves over the longer term, do not necessarily reflect their expectations about the price they expect to receive for the reserves in the short- to medium-term and may change each time reserves are calculated.

The significant variance in gas price assumptions underpinning the reserves estimates and, in particular, the uncontracted reserve estimates, highlights the need for more transparency in this area. The lack of publicly available information on the gas price assumptions underpinning producers’ reserves estimates means that market participants are unable to properly assess the risks surrounding the commercial viability of reserves. This could result in inefficient decisions being made by market participants and policy makers.

In relation to the gas price assumptions underpinning the uncontracted reserve estimates, the bottom end of the range (\$3.45/GJ) reflects a price a producer would use, with other contracted and uncontracted gas prices, to calculate a weighted average price to book reserves. The upper end of the range (\$14.50/GJ), on the other hand, reflects a producer’s ‘high case’ gas price assumption, which is based on its expectation of LNG netback prices.

Other than a few exceptions, producers’ assumptions of prices underpinning their uncontracted reserves estimates increase over the period 2018–2022. The average gas price assumed by producers across the east coast increases from \$7.70/GJ in 2018 to \$8.60/GJ in 2022.⁷¹ This upward trend can also be seen at a basin level, with the average gas price assumed by producers in the Bowen and Surat basins increasing from \$7.60/GJ to \$8.80/GJ between 2018 and 2022, and in offshore Victoria from \$7.95/GJ to \$8.60/GJ over the same period.

If actual gas prices are lower than the prices producers have assumed when developing their reserve estimates, then some of the reserves may need to be reclassified as contingent resources because they may no longer be commercially viable to recover. For example, if gas prices were to fall below \$9.50/GJ in 2022, then six producers would need to reassess the commercial viability of developing some of their reserves and, if the reserves were found to be no longer commercial to develop, reclassify them as contingent resources.

This latter observation highlights the sensitivity of reserve and resource estimates to gas price assumptions and reinforces the ACCC’s 2016 recommendation that reserves and resources be calculated using common price assumptions. As noted in box 2.1, the ACCC intends to carry out further work on this issue in early 2019 and consult with interested parties on the development of common price assumptions.

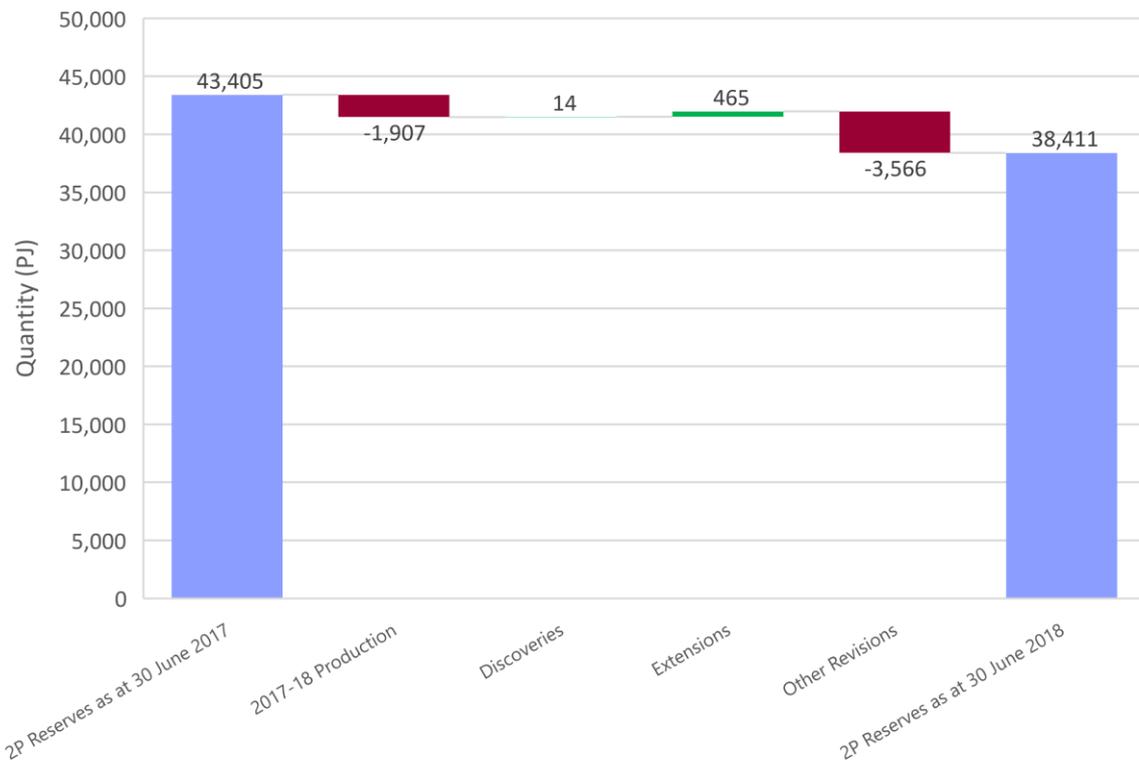
⁷¹ The median price is also expected to increase from \$7.35/GJ to \$8.50/GJ.

2.7. There was a significant decline in the quantity of 2P reserves in the east coast in the past 12 months

Chart 2.4 and table 2.3 show changes in 2P reserves over the period 30 June 2017 – 30 June 2018 due to:

- the production of gas
- the discovery of new fields or new reservoirs within existing fields with 2P reserves
- the extension of a field's proved area
- other revisions (including the write-down of reserves).

Chart 2.4: Changes in 2P reserves in the East Coast Gas Market, 30 June 2017 to 30 June 2018



Source: ACCC analysis of data obtained from producers.

Note: totals may not add up due to rounding.

Table 2.3: Changes in 2P reserves in the East Coast Gas Market by region, 30 June 2017 to 30 June 2018 (PJ)

	2P Reserves (30 June 2017)	Production	Discoveries	Extensions	Other Revisions	2P Reserves (30 June 2018)	%Change in 2P Reserves
Bowen/Surat Basins	38 882	-1 399	0	185	-3 819	33 848	-13%
Cooper Basin	1 018	-89	14	106	-57	991	-3%
Gippsland Basin	2 934	-320	0	0	250	2 864	-2%
Otway Basin	396	-70	0	168	23	517	31%
Bass Basin	78	-24	0	5	39	97	25%
Sydney Basin	17	-4	0	0	0	13	-24%
Clarence-Moreton Basin	80	0	0	0	0	80	0%
Total	43 405	-1 907	14	465	-3 566	38 411	-12%

Notes: totals may not add up due to rounding. Discoveries refer to changes to 2P reserves due to the discovery of new fields. Extensions refer to changes to 2P reserves due to the enlargement of proved areas within existing fields.

Chart 2.4 and table 2.3 show that 2P reserves fell by 4994 PJ between 30 June 2017 and 30 June 2018. This is largely attributable to production (1907 PJ) and other downward revisions (net 3566 PJ), which were not sufficiently offset by discoveries or extensions (collectively, 479 PJ).

While 2P reserves declined in most basins over the last 12 months, they grew in the Otway and Bass basins. Most of the growth in the Otway Basin arose through extensions while in the Bass Basin the growth arose through upward revisions.

The majority of changes relating to “other revisions” occurred in the Bowen and Surat basins, which predominantly contain coal seam gas fields. In the ACCC’s 2015 Inquiry, the ACCC noted that the LNG producers encountered challenges in the initial stages of CSG development that put at risk their ability to sustain the required level of production over the period of their LNG export agreements.⁷² The extent of these “other revisions” is significant and indicates that those challenges are continuing. It also highlights the uncertainty around the long-term performance of the Queensland coal seam gas fields. There have been a number of recent announcements of reserve write-offs, including:

- APLNG’s \$109 million dollar exploration write-off of the Gilbert Gully field.⁷³ Following a technical and commercial review of the area, APLNG determined that it had lower permeability and gas saturation compared to other areas in the Surat Basin, making commercial development of the gas field unlikely. APLNG had previously planned to drill 2,250 coal seam gas wells in the Gilbert Gully field at some point in the future.⁷⁴
- Origin’s write-down of its 2P Ironbark reserves by almost half.⁷⁵ With less gas considered economic to produce, the revision left Origin with a \$360 million dollar non-cash

⁷² ACCC, *Inquiry into the east coast gas market*, April 2016, p. 44.

⁷³ Origin, *Quarterly Production Report: For period ended 30 June 2018*, June 2018, p. 4.

⁷⁴ The Australian, *Origin Energy writes off exploration costs at Queensland coal seam gas field*, 31 July 2018, <http://online.isentialink.com/theaustralian.com.au/2018/07/31/1b60c105-fc8e-4086-b58e-3f408df1a62d.html>.

⁷⁵ Origin, *Investor presentation, 2018 half-year results: half year ended 31 December 2017*, 15 February 2018, p. 17.

impairment. Origin is currently exploring disposal of the project, with Senex and Santos named by media sources as potential buyers.⁷⁶

- Shell's \$390 million dollar write-off of some of its Queensland exploration and evaluation assets.⁷⁷

The ACCC also notes that Arrow Energy has re-classified 2933 PJ of its 2P reserves into 2C resources across its Queensland coal seam gas fields in the last 12 months, predominantly in the Bowen Basin. Arrow has informed the ACCC that its Bowen Basin Project requires further technical work and validation to improve economic production from the Project area, given the Bowen Basin contains deeper and tighter coals than the Surat Basin.

AGL's ATP1103 reserves in the Bowen Basin – relating to the permit area jointly held with Arrow – have also been re-classified from 2P reserves into 2C resources.

There are currently 33 780 PJ of 2P coal seam gas reserves in the Bowen and Surat basins. While a substantial quantity of these reserves have been classified as developed reserves (14 352 PJ), the majority are undeveloped reserves (19 429 PJ). There is therefore a greater degree of uncertainty surrounding the development of these reserves.

It is important to note that while 2P reserves have declined in the last year, they are able to fluctuate both ways. New discoveries, extensions and other upward revisions have the potential to increase the current 2P reserve levels if these are greater than production and other downward revisions.

While discoveries, extensions and other upward revisions in the past year have not been sufficient to offset declines from production and write-offs, this may change going forward, with more exploration and appraisal activity forecast to occur over the next three years (see below).

2.8. After a dip in recent years, exploration and appraisal activities are beginning to pick up

There are typically two key stages before development in the gas life cycle: exploration (searching for a potential source of gas) and appraisal (testing the source after discovery to define its potential more accurately).

Exploration generally involves conducting seismic surveys, followed by the drilling of exploration wells. Seismic surveys are a tool used by producers to develop a 2D or 3D image below the earth's surface for a particular area. The results are used by producers to determine where they should focus their exploratory drilling, the purpose of which is to find new gas reservoirs. Appraisal wells are then used to determine the extent of the reservoir after it is discovered.

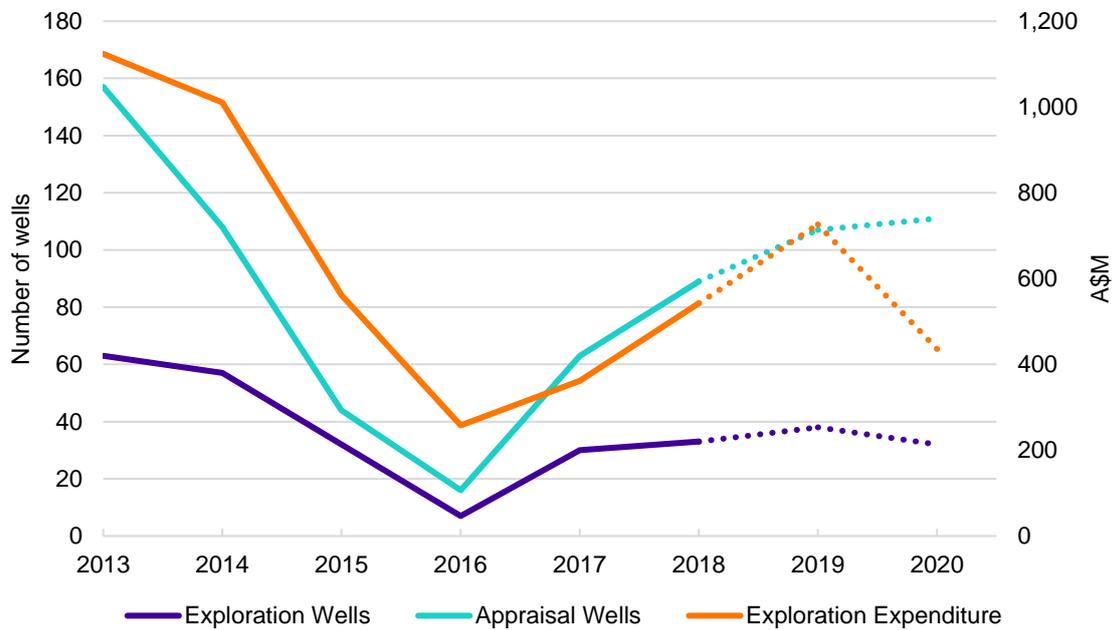
Chart 2.5 shows the total number of exploration and appraisal wells that were drilled in the east coast during the period 2013–2017, as well as the number of exploration and appraisal wells that gas producers and explorers expect to drill from 2018 to 2020. The chart also includes actual and expected exploration expenditure, being expenditure incurred or expected to be incurred to explore or evaluate gas resources. The information contained in

⁷⁶ Australian Financial Review, *Senex Energy bankers up for Origin Energy's Ironbark*, 29 October 2018, <https://www.afr.com/street-talk/senex-energy-bankers-up-for-origin-energy-s-ironbark-20181028-h176pn>; The Australian, *Santos favoured as Origin's Ironbark sale plans take shape*, 24 October 2018, <https://www.theaustralian.com.au/business/dataroom/santos-favoured-as-origins-ironbark-sale-plans-take-shape/news-story/ebc974a621a38dbd8c14b317bdd4aea5>.

⁷⁷ The Australian, *Shell's \$390m asset write off casts doubt on CSG reserves*, 2 May 2017, <https://www.theaustralian.com.au/business/mining-energy/shells-390m-asset-writeoff-casts-doubt-on-csg-reserves/news-story/acffbde24931dd974b2dd9bd892a4a3d>.

this chart is based on information provided by junior and major producers and explorers to the ACCC.

Chart 2.5: Number of wells drilled and exploration expenditure incurred (2013–2017) and proposed (2018–2020) in the East Coast Gas Market



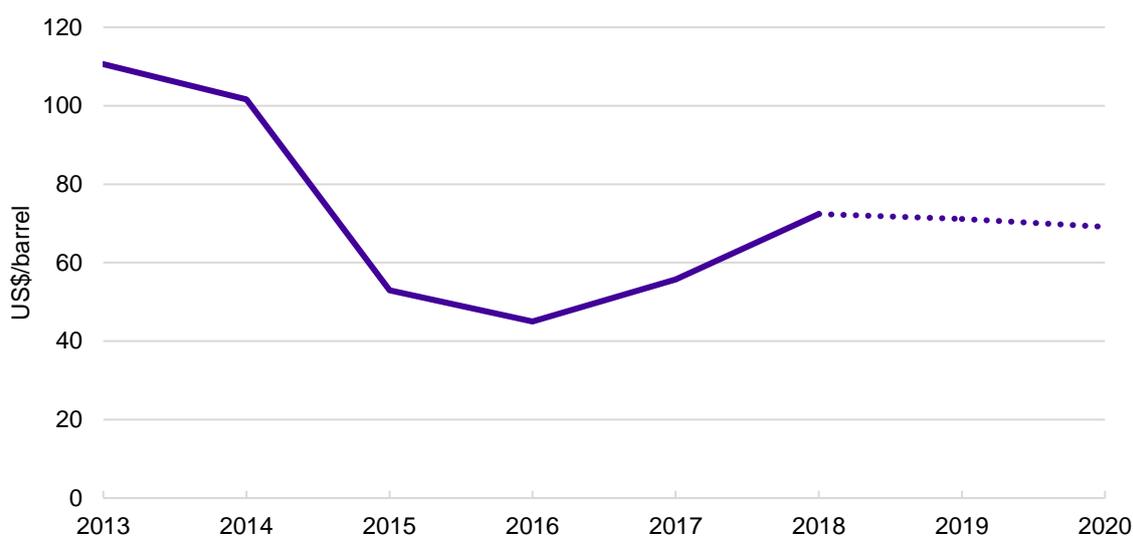
Source: ACCC analysis of data obtained from producers.

Note: While some exploration expenditure is expected in the Gunnedah, Clarence-Moreton and Poldas basins, these are not included in the above chart.

Chart 2.6 shows real Brent Crude oil prices, as at September 2018, which based on data from the Office of the Chief Economist (OCE).⁷⁸

⁷⁸ Department of Industry, Innovation, and Science, *Resources and Energy Quarterly*, September 2018, p. 56. <https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2018/index.html>.

Chart 2.6: Real Brent Crude oil prices, 2018 US\$/barrel



Source: The Department of Industry, Innovation and Science's Office of the Chief Economist, *Resources and Energy Quarterly* – September 2018.

Together, charts 2.5 and 2.6 show that the number of exploration and appraisal wells drilled, exploration expenditure and oil prices all follow a similar trend. Though not shown in the chart, data obtained by the ACCC on seismic surveys also follows the same pattern.

As explained in the ACCC's 2015 inquiry, the LNG projects and the key domestic producers are all oil exposed—from being a party to, or having a financial interest in oil-linked GSAs, or being directly involved in the production and sale of oil. Investment in exploration and appraisal in the east coast is therefore influenced by the global price of oil.

Low oil prices mean lower sales revenues and earnings for these parties, which in turn leaves less money available to spend on exploration and less incentive to engage in exploration and appraisal activities. Accordingly, low oil prices can lead to a decrease in exploration expenditure. Conversely, increases in the price of oil can result in increased investment and participation in gas exploration and appraisal activities.

As shown in chart 2.6, the Brent Crude oil price fell from an average of US\$110/barrel in 2013 to a low of US\$45/barrel in 2016, largely as a result of global over-supply.⁷⁹ Over the same period, the number of exploration wells drilled reduced from 63 in 2013 to 7 in 2016 (chart 2.5). The number of appraisal wells fell from 157 to 16. Exploration expenditure also took a downturn from \$1,124 million in 2013 to \$258 million in 2016. As exploration and appraisal activities precede gas development (sometimes by many years), it can be expected that this period of limited exploration activity will have flow on effects on production levels and supply into the future.

Current producer projections indicate noticeably more exploration and appraisal activity planned for the next three years (chart 2.5). There are 38 exploration wells and 107 appraisal wells planned for 2019 and 32 exploration and 111 appraisal wells planned for 2020. While this is a positive development, these numbers are still significantly less than the activity in 2013 – the number of exploration wells expected to be drilled in 2019 will be 40% lower than 2013, while the number of appraisal wells expected to be drilled in 2019 will be 32% lower.

⁷⁹ ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2017, p. 80.

Whether current exploration and appraisal plans are carried out and the level of any future activities will likely depend, at least to an extent, on the price of oil. As at 22 October 2018, the price of Brent Crude oil was US\$79.63/barrel.⁸⁰ The OCE forecast for Brent Crude oil suggests that prices will remain relatively stable over the next three years, averaging US\$72/barrel in 2018, US\$71/barrel in 2019 and around US\$69/barrel in 2020 (chart 2.6).

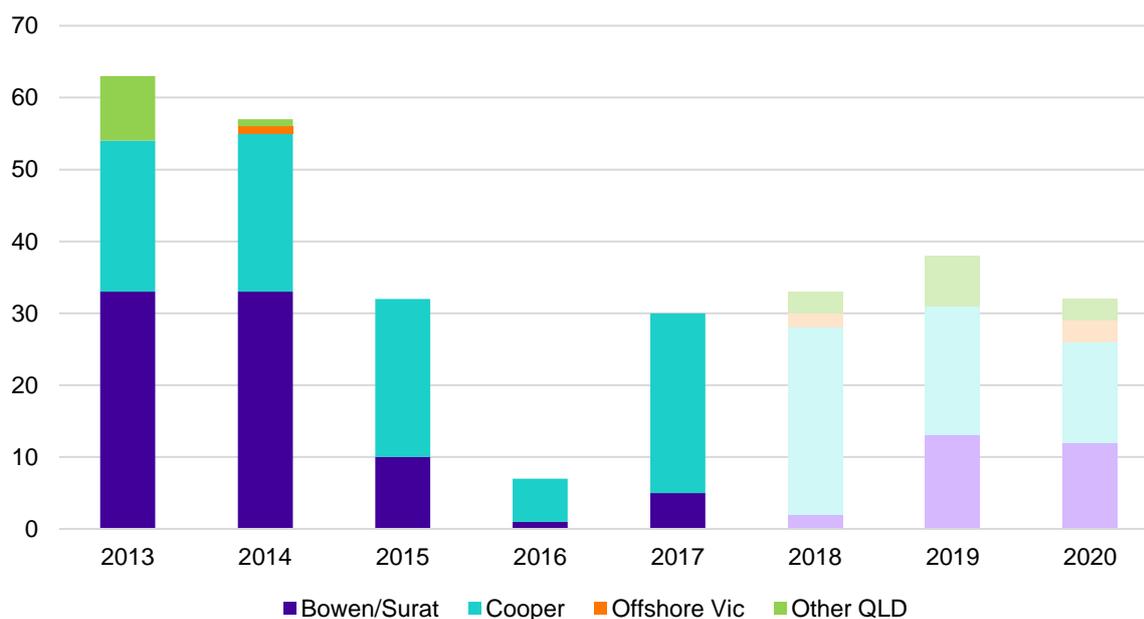
The OCE noted, however, that there are a number of uncertainties surrounding these forecasts. The sources of these uncertainties include: world supply shortages due to sanctions on Iran and uncertainty around production from Libya and Nigeria.⁸¹ Any downturn in global economic activity will also weigh on prices.⁸²

Given that there can be lengthy lead times between when gas is first discovered and when it is developed for commercial use, more exploration needs to occur in the short-term to ensure there is adequate supply in future years.

2.9. Offshore Victoria has seen limited exploration and appraisal activities over the last 5 years and this is expected to continue

Chart 2.7 provides more detail on the number of exploration wells that have been drilled, and that producers expect to drill, in the East Coast Gas Market over the period 2013 to 2020, broken down by region.

Chart 2.7: Number of exploration wells drilled (2013–2017) and proposed to be drilled (2018–2020) in the East Coast Gas Market, by region



Source: ACCC analysis of data obtained from producers

Note: Offshore Victoria includes the Bass, Gippsland and Otway Basins.

The chart shows that over the past five years, most exploration activity has occurred in the Cooper Basin, followed by Queensland.

⁸⁰ Bloomberg, Energy Markets: Crude Oil and Natural Gas, viewed 30 November 2017, <https://www.bloomberg.com/energy>.

⁸¹ Department of Industry, Innovation, and Science, *Resources and Energy Quarterly*, September 2018, p. 56, <https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2018/index.html>.

⁸² *ibid.*

Cooper Basin exploration activity has remained relatively consistent (with the exception of 2016). This may reflect efforts by producers in the Cooper Basin to reduce development and operating costs, allowing a more sustained level of drilling activity.

Exploration activity in the Bowen and Surat Basins were a lot higher in 2013 and 2014 compared to subsequent and future years. This is likely due to Queensland producers and in particular, the LNG projects, having undertaken the necessary exploration in earlier years and now being in the next stage of their operations (chart 2.8 below). Queensland producers, however, are expected to engage in some exploration activity in the coming years.

On 27 September 2018, the Queensland government announced four companies won tenders as part of Queensland's annual exploration program.⁸³ Chi Oil and Gas will be looking for gas solely for the Australian market, while Armour Energy, Cypress Petroleum and Bridgeport Energy will be able to supply any gas they find to either the Australian or export market.

As chart 2.7 shows, there has been very limited gas exploration activity in offshore Victoria and this is not expected to increase substantially in the coming years. No onshore exploration is expected in NSW or Victoria due to the moratoria and regulatory restrictions that apply in those states.

As reported by the Department of Industry, Innovation and Science in its *Offshore South East Australia Future Gas Supply Study*, the major known gas fields in south east Australia are significantly depleted and there are few prospects of new gas supply emerging.⁸⁴

In the December 2017 report, the ACCC reported that Esso Australia owned an offshore gas field in Bass Strait, called Dory, which had the potential to contain a significant quantity of gas.⁸⁵ In 2018, Esso drilled two exploration wells to test Dory, but was not able to find commercial quantities of gas.⁸⁶

In August 2018, the Federal Government directed the National Offshore Petroleum Titles Administrator to conduct a review into the commercial value of south east Australian offshore petroleum titles. The review will determine if there are resources that could be brought into production in the Victorian and Tasmanian offshore areas.⁸⁷ The review follows the findings of a new study commissioned by the COAG Energy Council, which considered how effective the petroleum licensing regulations are in driving prompt commercial development of gas resources and in supporting exploration and expenditure.⁸⁸ If the review finds that there are commercially viable resources in offshore Victoria and Tasmania, it could lead to an increase in production as well as exploration and appraisal activities.

While not shown in chart 2.7, information obtained by the ACCC indicates that more exploration wells have been drilled in brownfield areas (areas with existing infrastructure and

⁸³ Lynham, A (Minister for Natural Resources, Mines and Energy), Queensland fires up for gas supply challenge, media release, Queensland Government, 27 September 2018, <http://statements.qld.gov.au/Statement/2018/9/26/queensland-fires-up-for-gas-supply-challenge>.

⁸⁴ Department of Industry, Innovation and Science, 'Offshore South East Australia Future Gas Supply Study', November 2017, <https://industry.gov.au/resource/UpstreamPetroleum/OffshorePetroleumDevelopment/Documents/Offshore-South-East-Australia-Future-Gas-Supply-Study.pdf>

⁸⁵ ACCC, *Gas Inquiry 2017-2020 Interim report*, December 2017, p. 96.

⁸⁶ The Australian, *Exxon's \$120m Bass Strait bet fails to deliver gas*, 15 November 2018, <http://online.isentialink.com/theaustralian.com.au/2018/11/14/6a31e122-dd19-43da-8bab-17cee22566f8.html>.

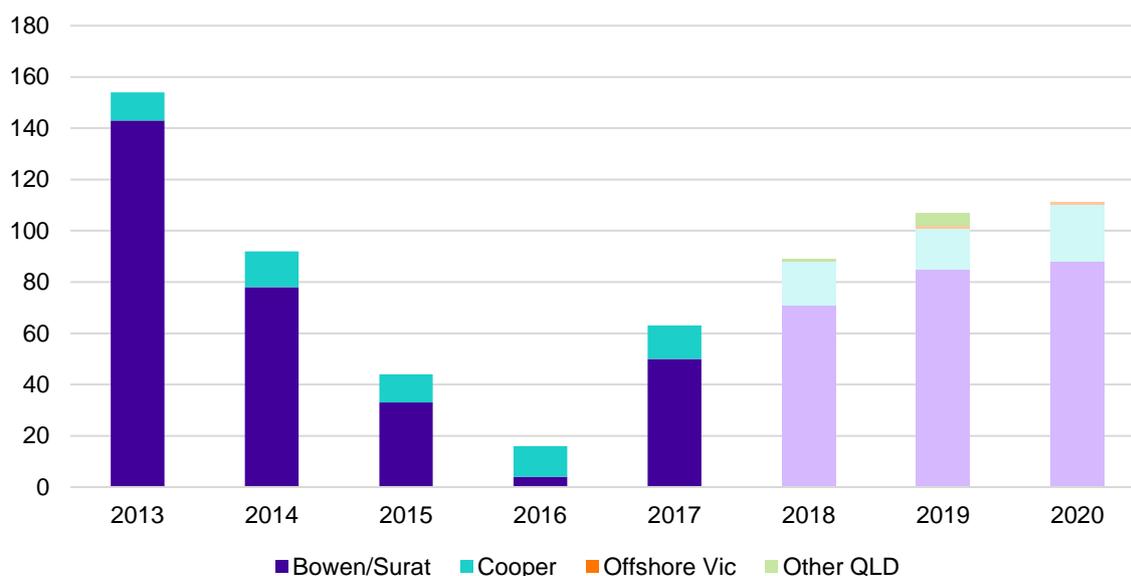
⁸⁷ Canavan, M (Minister for Resources and Northern Australia), Review of the S.E. Australian offshore petroleum leases, media release, Parliament of Australia, 17 August 2018, <https://www.minister.industry.gov.au/ministers/canavan/media-releases/review-se-australian-offshore-petroleum-leases>.

⁸⁸ Canavan, M (Minister for Resources and Northern Australia), Petroleum licensing report points to reforms, media release, Parliament of Australia, 10 August 2018. <https://www.minister.industry.gov.au/ministers/canavan/media-releases/petroleum-licensing-report-points-reforms>

known resources) than greenfield areas (new areas for development) in the last five years. However, this is expected to change with more greenfield than brownfield wells forecast to be drilled in the period 2018 to 2020. This likely reflects increased incentives to find more gas given current market conditions and oil and gas price expectations.

Chart 2.8 below shows the number of appraisal wells that have been drilled, and that producers expect to drill, in the East Coast Gas Market over the period 2013 to 2020, broken down by region. As mentioned above, appraisal is the next phase of operation towards gas development.

Chart 2.8: Number of appraisal wells drilled (2013–2017) and proposed to be drilled (2018–2020) in the East Coast Gas Market, by region



Source: ACCC analysis of data obtained from producers.

Note: Offshore Victoria includes the Bass, Gippsland and Otway Basins. The Gunnedah Basin is not included in this chart.

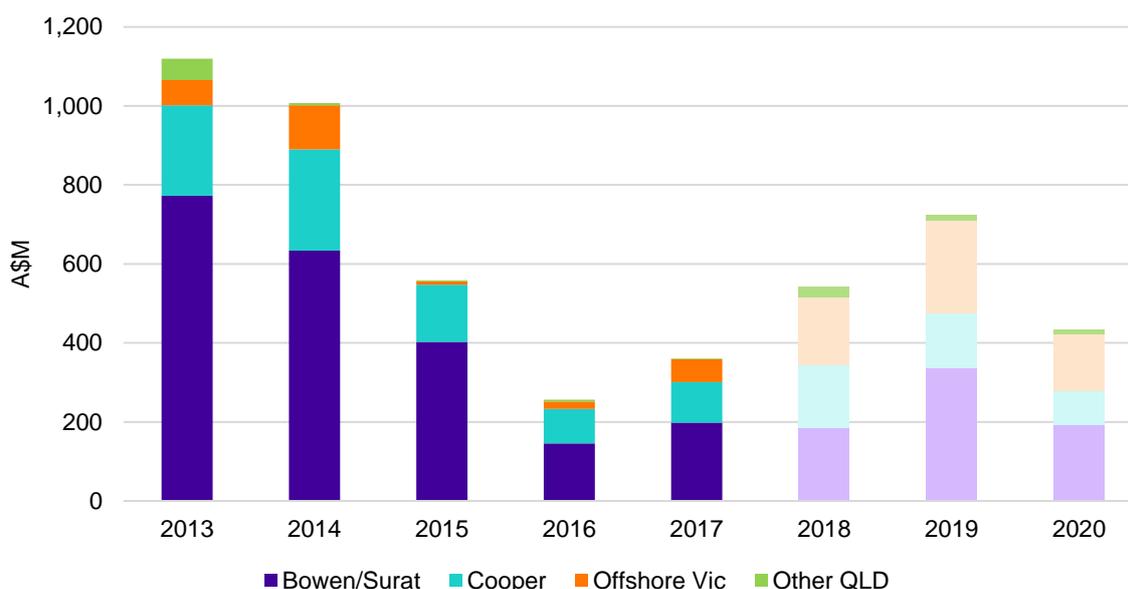
As with exploration (chart 2.7), there has been a relatively consistent level of appraisal activity in the Cooper Basin, with producers and explorers forecasting this trend to continue.

The chart also shows that appraisal activity in the Bowen and Surat Basins is expected to be greater than forecast exploration activity in these areas (chart 2.7). As mentioned above, this is likely due to Queensland producers moving into the next phase of operation, namely the drilling of appraisal and development wells.

As with exploration, the least amount of appraisal activity has and is expected to occur in offshore Victoria.

Chart 2.9 shows a breakdown of exploration expenditure in the east coast, by region, for the period 2013 to 2020.

Chart 2.9: Exploration expenditure incurred (2013–2017) and proposed (2018–2020) in the East Coast Gas Market, by region



Source: ACCC analysis of data obtained from producers.

Note: Offshore Victoria includes the Bass, Gippsland and Otway basins. While some exploration expenditure is expected in the Gunnedah, Clarence-Moreton and Poldas basins, these are not included in the above chart. 'Unassigned' expenditure is also not included.

Unlike exploration and appraisal activities, chart 2.9 shows that exploration expenditure in offshore Victoria is forecast to increase considerably over the next three years, highlighting the substantial costs associated with these kinds of activities. While future exploration and appraisal activities in offshore Victoria are expected to be limited (charts 2.7 and 2.8), the majority of the forecast activities relate to greenfield areas. As mentioned in section 2.9 above, greenfield areas lack existing infrastructure. Activities associated with these areas are therefore likely to have higher costs.

When it comes to investment in exploration and appraisal activities, it is important to note that these tend to be sunk costs, where the investments have few alternative uses in the event that no gas is discovered. These activities have an uncertain probability of success, which is why strong incentives (such as high oil prices) are needed for producers to contribute the capital required to undertake them.

2.10. Production costs across the East Coast Gas Market are rising

The majority of gas in the East Coast Gas Market has historically been produced from conventional reserves in South Australia and offshore Victoria, with the cost of gas production and wholesale gas prices being relatively low.

However, the commencement of LNG exports from Gladstone in 2015 and the linking of the East Coast Gas Market with the international LNG market has altered domestic supply dynamics and has changed the alternatives available to both buyers and sellers of gas across the market by creating opportunities for gas producers to sell gas for export.

The high level of international LNG prices—relative to historical domestic prices—and domestic producers' access to the LNG market has made the production of higher-cost gas more economic. This, combined with the significant increase in east coast gas demand driven by the LNG producers (for both newly developed unconventional and older

conventional gas reserves) has accelerated the development of reserves across the market, causing lower-cost gas from conventional reserves to become depleted at a faster rate than it otherwise would have.

These factors have, in turn, resulted in a greater proportion of gas production in the East Coast Gas Market coming from higher-cost conventional reserves and unconventional sources of gas such as CSG. The cost of gas production will play an important role in the development of the East Coast Gas Market.

The ACCC engaged Core Energy (Core) to develop detailed and up-to-date production cost estimates. The results of Core's work, which has been developed using the method outlined in box 2.2, is summarised below. Core's report is available on the ACCC's website.

Box 2.2: Method used by Core Energy to estimate production costs

Core estimated the cost of gas production for all 2P reserves across the east coast as at 31 December 2017, including supply regions that are not currently in production. Core developed these estimates using the following steps:

- Quantify reserves—The total quantity of 2P gas reserves across the east coast were estimated based on Core's market intelligence and assessment of public reserve disclosures by project operators and government authorities.
- Define supply regions—East coast 2P reserves were divided into individual supply regions based on geological basins and sub regions defined by geological and geographical boundaries.
- Estimate production quantities—Historical and forward gas production quantities were estimated for each supply region based on Core's analysis of the historical performance of gas wells either currently producing gas or wells comparable to those in production.
- Estimate production costs—Estimates were developed of historical and forward breakeven costs of production for each supply region. The breakeven cost for a supply region is defined as the ex-plant gas price that would result in a zero net present value for historical and future post-tax cash flows assuming a 10 per cent rate of return.

Core's production cost modelling was developed using a range of information sources including company reports and investor presentations, statutory reports, and Core's market intelligence. Core employed a bottom-up cost methodology incorporating capital expenditure, operating expenditure, taxes and royalties payable by operators depending on the relevant supply region and resource type.

In addition, Core conducted an operator review process whereby it engaged with some key east coast gas producers on its initial cost estimates. Following this consultation, Core refined its inputs and method of estimating production costs as necessary to reflect responses from producers.

2.10.1. Core Energy's estimates

Core estimated production costs using two separate methods: 'full lifecycle costs' of production and 'forward costs' of production.

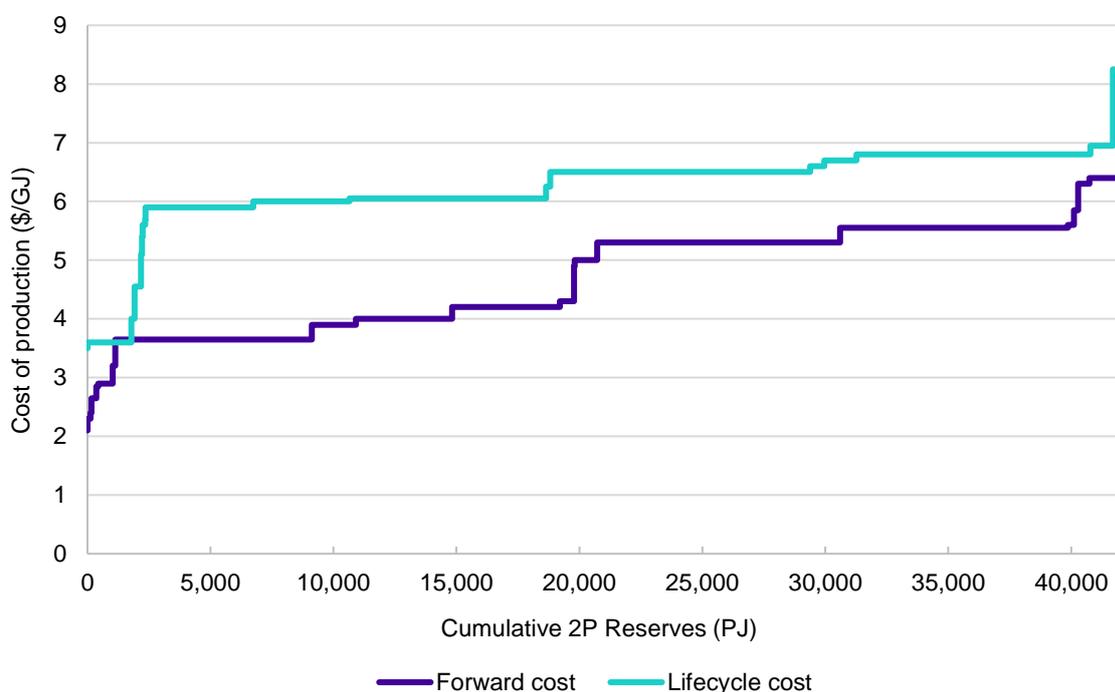
Core notes in its report that gas producers, to have an incentive to invest in gas production over the long-term, would expect to receive gas prices that are at least sufficient to recover all costs incurred over the life of an investment, including a return on capital.⁸⁹ Core has therefore estimated full lifecycle costs of production that reflect the breakeven gas price for a supply region's entire cash flows over lifetime production volumes. This includes the costs of gas production that are yet to be incurred as well as historical or sunk costs that have been incurred to date.

⁸⁹ Core Energy, *Gas Production Cost Estimates: Eastern Australia*, November 2018, p. 12.

However, Core notes in its report that under competitive market conditions a producer may have an incentive, at a given point in time, to continue producing gas into the future as long as there is a reasonable expectation that a sufficient rate of return can be achieved on the associated future investment.⁹⁰ This may be the case even if the historical or sunk cost elements may not achieve adequate returns. Therefore, in addition to estimating the lifecycle costs of gas production facing producers, Core estimated the gas prices that would enable producers to break even, taking into account only the future cash flows of a given supply region and for only future production volumes.

The charts below show Core’s lifecycle and forward production cost estimates. The bars in charts 2.11–2.14 show the high to low range of Core’s cost estimates for both conventional and unconventional supply regions, while the white lines represent Core’s best estimates. The lines in chart 2.10 reflect Core’s best estimate for all 2P reserves in the east coast.

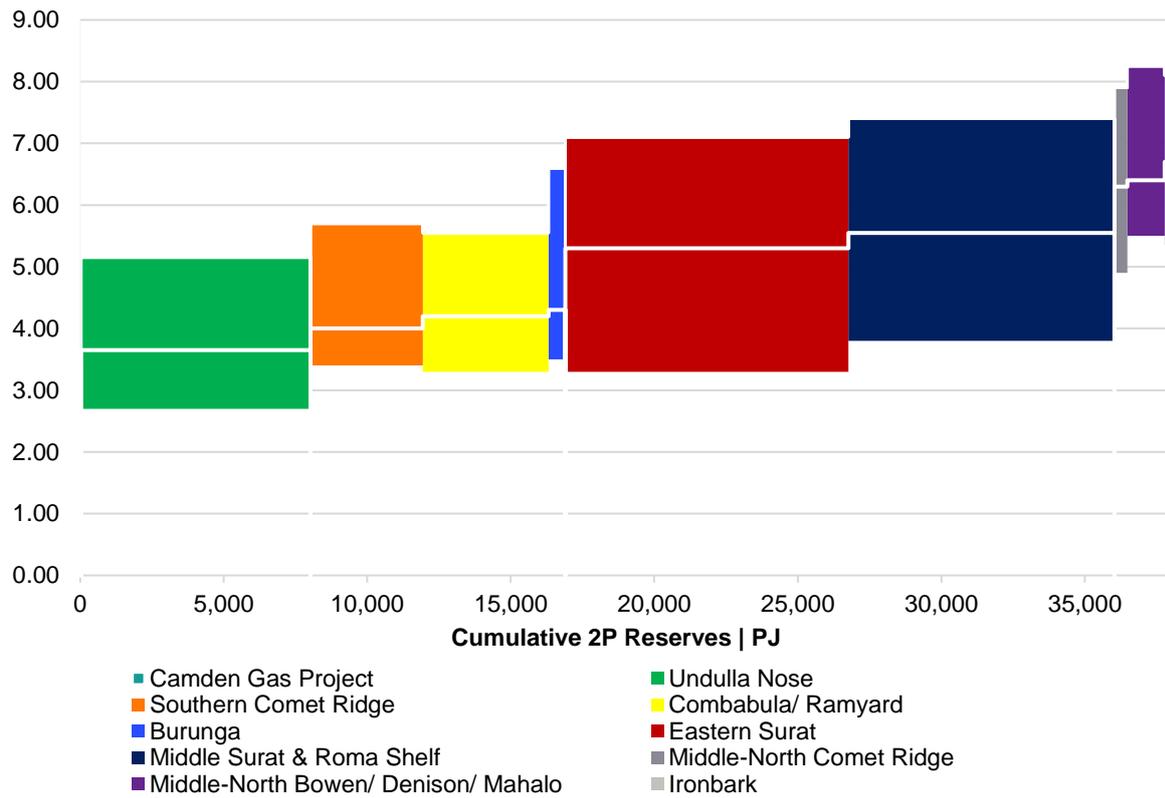
Chart 2.10: Lifecycle and forward cost estimates in the East Coast Gas Market (all 2P reserves)



Source: Core Energy

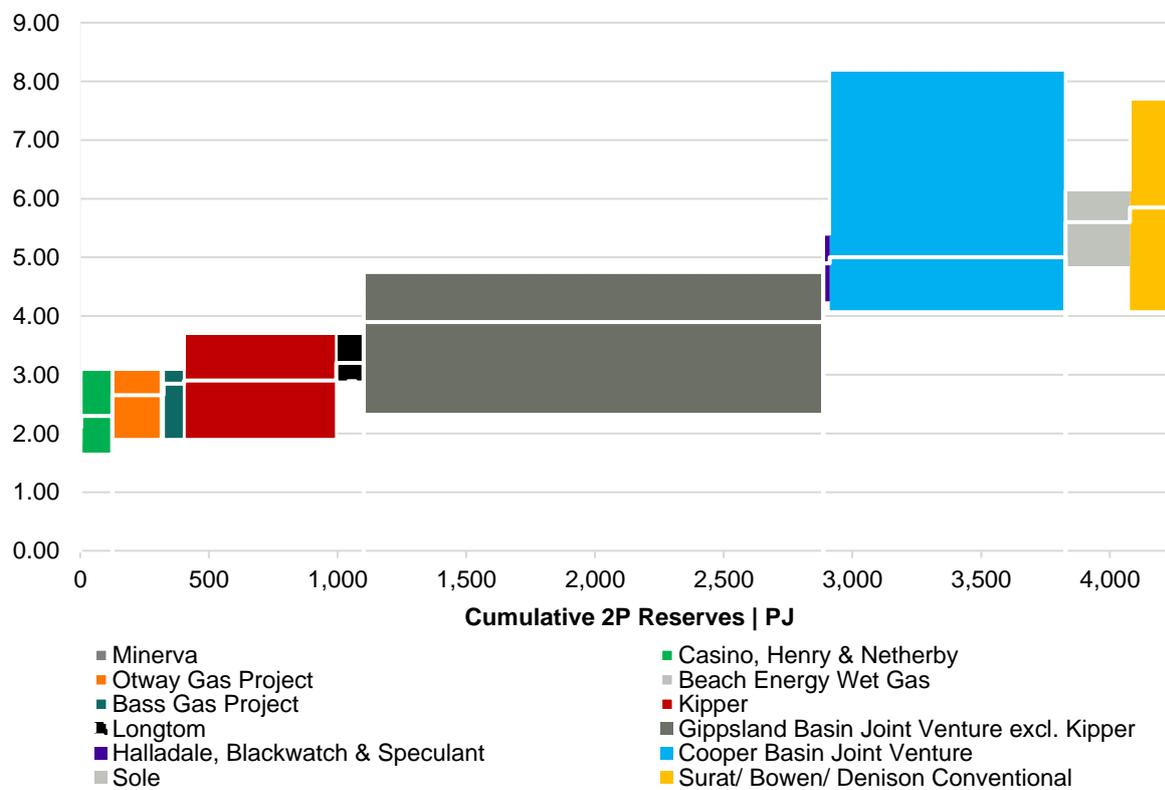
⁹⁰ Core Energy, *Gas Production Cost Estimates: Eastern Australia*, November 2018, p. 12.

Chart 2.11: Forward cost estimates (unconventional)



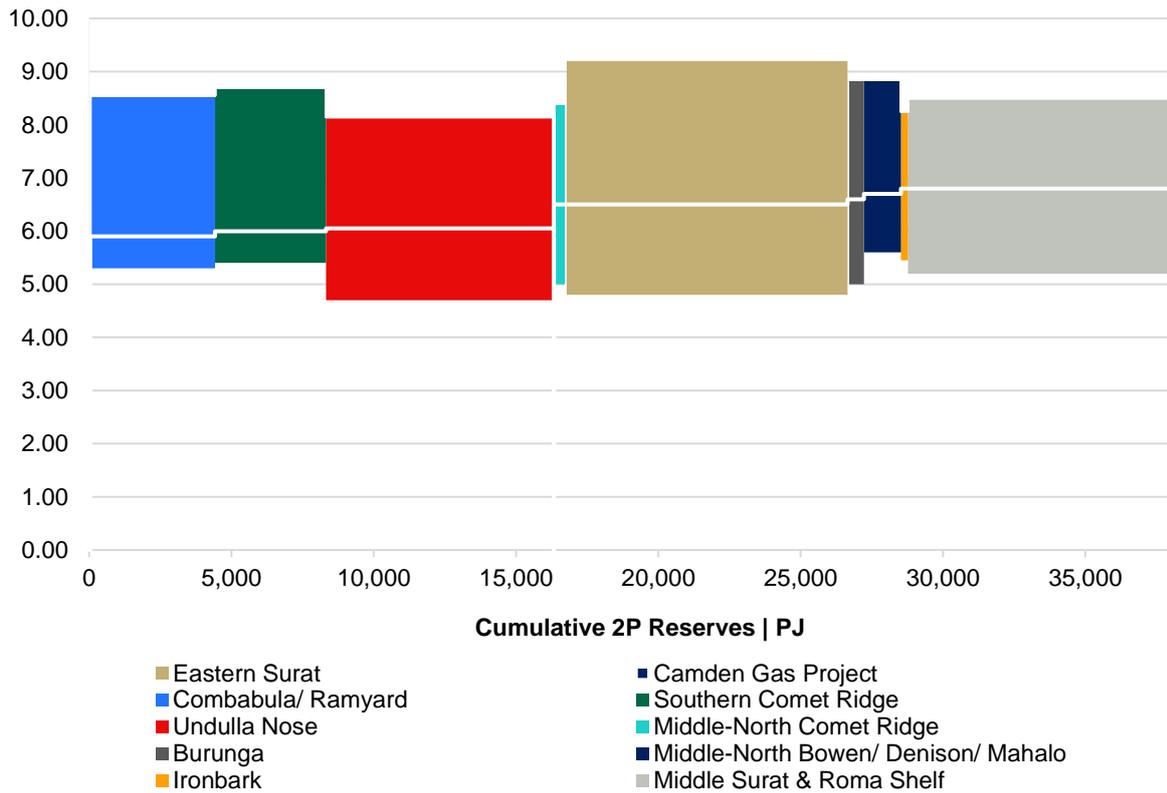
Source: Core Energy

Chart 2.12: Forward cost estimates (conventional)



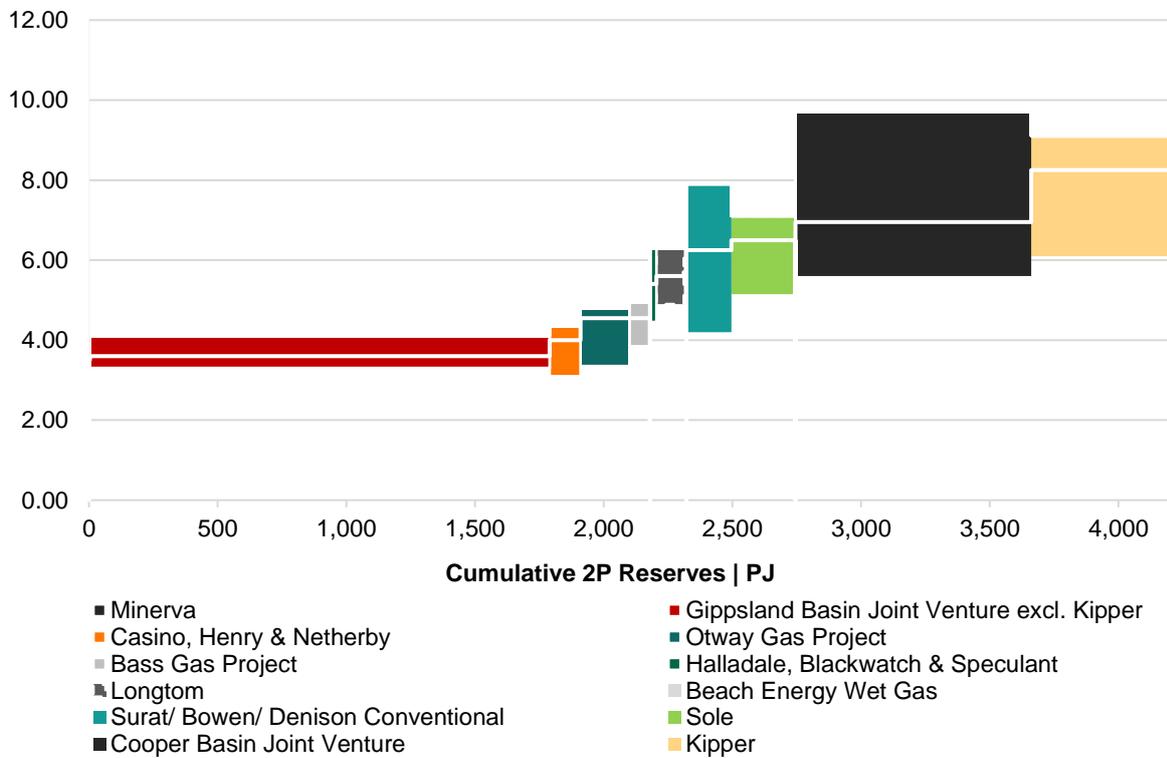
Source: Core Energy

Chart 2.13: Lifecycle cost estimates (unconventional)



Source: Core Energy

Chart 2.14: Lifecycle cost estimates (conventional)



Source: Core Energy

Core's estimates show that the conventional sources of gas production in the east coast, which have traditionally been used to supply the domestic market, are relatively low-cost compared to unconventional and newly developed conventional gas reserves.

As shown in chart 2.10, which includes both forward and lifecycle production cost estimates in all supply regions across the east coast, around 90 per cent of all 2P reserves estimated by Core have a lifecycle cost of around \$6/GJ or higher, and around half of reserves have a forward cost of more than \$5/GJ.

Almost all of these higher-cost sources of gas are unconventional or newly developed conventional reserves which, in the absence of further conventional gas exploration in the Southern States, the market will largely depend upon for future gas supply. Since the cost of gas production sets the floor in any gas price negotiation (see box 3.5), the cost of producing gas from these reserves will likely become the minimum price of gas in the East Coast Gas Market as traditional sources of supply are further depleted.

Core's estimates are discussed in further detail below.

Conventional gas

As shown in chart 2.14, Core estimates the lifecycle costs of the majority of conventional gas reserves on the east coast to be under \$5/GJ. The lifecycle costs for the GBJV supply region and the developed component of the Cooper Basin Joint Venture—which have historically been the major sources of supply for the domestic market—are \$3.60/GJ and \$4.50/GJ, respectively.

However, the acceleration of east coast gas production over recent years (due in large part to LNG-driven increases in demand) has caused these traditional and relatively low-cost sources of supply to become depleted at a faster rate than they otherwise would have. As illustrated in chart 2.12 above, remaining gas reserves in these supply regions are expected to be more costly to produce relative to full lifecycle costs (particularly in the case of the GBJV—see box 2.3). In particular, the forward costs for the GBJV supply region and the undeveloped component of the Cooper Basin Joint Venture are estimated at \$3.90/GJ and \$6.25/GJ, respectively.

Box 2.3: Gippsland Basin Joint Venture

As illustrated by chart 2.14 above, the Gippsland Basin is a major source of conventional gas for the East Coast Gas Market. It has historically represented a majority of the conventional gas reserves from offshore Victoria, and produced at relatively low cost.

However, in its *Offshore South East Australia Future Gas Supply Study* (November 2017), the Department of Industry, Innovation and Science found that the major known offshore gas fields of south east Australia have been developed and are significantly depleted.⁹¹ The study found that future production sources will continue to shift from the high volume, shallow depth, high-quality gas fields to low volume, deeper, low-quality gas fields.⁹²

As previously reported, Esso, the operator of the GBJV, has explained to the ACCC that the GBJV's largest legacy fields (predominantly developed in the 1960s) are reaching the end of their life and have limited quantities of recoverable gas left.⁹³ One of the GBJV's large original gas fields has depleted earlier than expected, with another two expected to deplete in the early 2020s.⁹⁴

The GBJV has accelerated production from its legacy gas fields over recent years to meet increasing demand, including the drawdown of gas cycled through reservoirs used to increase system capacity during peak winter demand months. However, Esso stated that the GBJV is unable to sustain these production levels as low impurity resources from its legacy fields decline.

Esso has also explained to the ACCC that increased production by the GBJV is constrained by infrastructure capacity limits. Gas from newer sources of supply which are smaller in quantities and deeper underground, such as the Kipper gas field owned by the GBJV and Mitsui, may have higher levels of impurities and may require an additional level of gas processing.⁹⁵

Gas from the Kipper field contains higher levels of mercury and carbon dioxide than historic fields in the Gippsland Basin. The joint venture participants constructed a new Gas Conditioning Plant to remove these impurities, which significantly increased the cost of production. Esso informed the ACCC that further investment into an additional plant (or additional capacity) will be required to maintain production level as it increasingly relies on higher impurity gas.⁹⁶

As shown in charts 2.14 and 2.12 above, the forward cost estimates for the GBJV supply region are at a similar level to lifecycle costs. This is in contrast to other conventional and CSG supply regions where forward costs tend to be significantly lower than lifecycle costs. As noted above, Core's estimates of forward costs capture all production costs yet to be incurred for quantities of reserves yet to be produced. These results indicate that, for the remaining quantities of gas able to be extracted by the GBJV from the Gippsland Basin, the associated costs are significantly higher than historical levels.

Core's estimates show that, in addition to the increasing costs of older and more developed conventional reserves, the estimated cost of producing newer conventional reserves is also high relative to traditional sources of supply. Chart 2.14 shows that the estimated lifecycle costs of conventional gas developments that have either begun production in recent years or are yet to commence production⁹⁷ range between \$5.40/GJ (Halladale, Blackwatch and Speculant) and \$8.25/GJ (Kipper).

⁹¹ Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, November 2017, p. 6.

⁹² *ibid.*

⁹³ ACCC, *Gas Inquiry 2017-2020 Interim report*, December 2017, p. 30.

⁹⁴ *ibid.*

⁹⁵ *ibid.*

⁹⁶ *ibid.*

⁹⁷ This includes the following developments: Kipper, Sole, Cooper Basin (undeveloped), Beach Energy West Gas, and Halladale, Blackwatch and Speculant.

Unconventional gas

With the lower-cost conventional gas fields that traditionally served the domestic market in decline, additional gas for the domestic market is increasingly being supplied from unconventional gas reserves, particularly the CSG fields in Queensland.

Information obtained by the ACCC from east coast producers shows that, as at 30 June 2018, more than 88 per cent of 2P reserves in the east coast are CSG, while around 85 per cent of 2C resources are made up of CSG and other unconventional gas. Therefore, in the absence of further exploration of conventional supply sources in the Southern States, as current conventional supply sources in the east coast continue to be depleted, the market will become increasingly reliant on CSG for domestic supply.

The costs of CSG production in the east coast are expected to be high relative to the traditional sources of supply discussed above. As shown in chart 2.13, Core estimates that the lifecycle costs of almost all unconventional gas reserves in the east coast are between \$5.90/GJ and \$6.80/GJ.

These higher costs can be explained by the relatively higher ongoing levels of capital expenditure required for CSG production compared to production from conventional reserves. Unconventional gas reserves typically occur in reservoirs with very low permeability compared to conventional reservoirs, and so for these reserves, techniques such as horizontal drilling and hydraulic fracturing are often necessary for economic gas extraction. These unconventional gas fields also require ongoing capital expenditure to pay for the large number of wells that are required to be drilled over the life of the fields to maintain production.

However, going forward there may be downward pressure on production costs, particularly for the development of unconventional gas reserves. Over time, gas producers should be able to take advantage of new technologies and optimise unconventional gas production while cutting drilling costs.

Santos, for example, has reported that it achieved significant cost savings in operating production from GLNG's gas fields. Projects are now being completed and approved at about half the cost estimates they were two years ago, with well costs down nearly three quarters and drilling times halved.⁹⁸ In addition, EnergyQuest has recently noted that Santos has reduced Cooper Basin drilling costs by 50 per cent since 2015, and that overall production costs have fallen by 13 per cent over the first half of 2018.⁹⁹

Information obtained by the ACCC from major east coast gas producers indicates that similar levels of cost reduction are being achieved across a range of CSG supply regions. The data collected by the ACCC shows that, for the majority of CSG supply regions in Queensland, operators have generally experienced reductions in both the average cost of drilling, and the time taken to drill, gas development wells over recent years. For some CSG regions with significant quantities of reserves (around half of current 2P reserves), average drilling costs have fallen by between half and three quarters, while average drilling times have fallen by up to half over the past few years.

⁹⁸ The Australian, *Well, well, well: how Santos GLNG slashed costs, drilling times*, 23 March 2018 <https://www.theaustralian.com.au/business/mining-energy/well-well-well-how-santos-glng-slashed-costs-drilling-times/news-story/ac8b250817ae9e059820f68ef5177a8c>.

⁹⁹ EnergyQuest, *EnergyQuarterly*, September 2018, p. 76.

3. Domestic price outlook for 2019 and recent experiences of C&I gas users

3.1. Key points

- Prices paid across the East Coast Gas Market in the first half of 2018 have continued to rise as legacy gas supply agreements (GSAs) expire and new, higher-priced GSAs take their place. This increase was mostly driven by prices paid by gas buyers in the Southern States. In the first quarter of 2018, there was a 29 per cent quarterly increase in prices paid to producers in the Gippsland, Bass and Otway basins, and a 33 per cent quarterly increase in prices paid by southern commercial and industrial (C&I) gas users to retailers/aggregators.
- Most gas commodity prices under offers made between April and August 2018 for gas supply in 2019 were priced between \$9/GJ and \$12/GJ. This represents an increase on prices offered in late 2017 and early 2018, which ranged in the high-\$8 to \$11/GJ range.
- Price offers across the domestic market have, on average, tracked export parity prices. The increase in price offers over the middle months of 2018 was commensurate with an increase in expected LNG netback prices at Wallumbilla for 2019, which rose from around \$9/GJ at the end of April 2018 to over \$11.50/GJ by the end of August 2018.
- The gap between producer and retailer/aggregator price offers narrowed between April and August 2018. While the averages of offer prices from producers and retailers/aggregators have been broadly aligned, some retailers/aggregators entered into GSAs with C&I gas users at lower prices than producers.
- On average, the gas commodity prices currently expected to be paid under GSAs for gas supply in 2019, entered into between January 2017 and the end of August 2018, are:
 - \$8.36/GJ by all buyers to Queensland producers
 - \$11.76/GJ by C&I gas users to Queensland retailers/aggregators
 - \$9.37/GJ by all buyers to producers in the Southern States
 - \$9.91/GJ by C&I gas users to retailers/aggregators in the Southern States.
- While the averages of prices for 2019 gas supply have followed export parity prices over mid-2018, prices are well above the estimated costs of gas production across the east coast.¹⁰⁰ With the quantity-weighted average of production costs estimated at \$4.91/GJ in Queensland and \$3.76/GJ in the Southern States, the prices recently offered and agreed for 2019 gas supply are likely to result in producers achieving significant margins.
- At current prices, many C&I gas users are facing very challenging long-term investment decisions, with some increasingly likely to relocate or close their operations. While more offers were accepted by C&I gas users over mid-2018 than in early 2018, some users are increasingly re-contracting for shorter periods and much closer to the end of their existing GSAs, hoping that domestic gas prices may ease.

¹⁰⁰ These estimates of production costs are based on Core Energy's report for the ACCC, *Gas Production Cost Estimates: Eastern Australia*, November 2018. See section 2.10 for a discussion of the report.

3.2. Introduction

In this chapter we report on the gas price outlook for the East Coast Gas Market for 2019. This includes analysis of prices paid under GSAs between 2015 and 2018, prices agreed for 2019 under recently executed GSAs, and prices in offers and bids for gas supply in 2019. As part of this, we compare domestic price offers for 2019 against LNG netback price expectations for 2019. We also report on the recent experience of C&I gas users seeking supply for 2019. Finally, we report on recent prices paid in short-term trading markets and recent Victorian gas futures trading.

Box 3.1: Prices reported in this chapter

Unless specified otherwise, the following applies to the analysis of invoices, GSA, offers and bids in this chapter.

- The prices reported are gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges. The prices charged for transportation have been excluded from the analysis to enable a more direct comparison between the prices paid by buyers with different 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 averages of prices are reported, these are quantity-weighted averages of prices.
- The prices of individual transactions are not all 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 this chapter.

While Northern Territory suppliers will be able to supply gas into the East Coast Gas Market once the Northern Gas Pipeline (NGP) is commissioned, we have excluded Northern Territory suppliers' prices from the analysis in this chapter and commented separately where relevant. Due to the relatively high transport cost component involved in delivering Northern Territory gas to East Coast Gas Market, it is less meaningful to compare only the gas commodity components of these prices with those in the east coast.

3.3. Gas prices paid in the East Coast Gas Market 2015–2018

In this section, we update our two series that track the prices that were invoiced under GSAs by a range of suppliers in the East Coast Gas Market over the period 2015–2018. The first series is based on invoices that were issued by producers to a range of gas buyers, including retailers, C&I gas users and gas powered generators (GPGs). The second series is based on invoices that were issued by retailers to C&I gas users.

Both series were most recently presented in our April 2018 report, and covered the period from Q2 2015 to Q4 2017 inclusively. In this report, both series have been extended using newly obtained information to include data for the first half of 2018.

Box 3.2 below sets out the ACCC's approach to reporting on invoiced prices.

Box 3.2: Approach to reporting on invoiced prices

The information in this box should be read in conjunction with information in box 3.1. The following also applies to the invoiced prices reported in this section.

- For the producer invoice series, we have included invoices under all GSAs entered into by producers. This includes some GSAs that were for a term of less than one year and with an annual contract quantity of less than 0.5 PJs.
- For the producer invoice series, from December 2017 onwards we have included transaction notices that were for a term of one year or more and an annual contract quantity of more than 0.5 PJs. Transaction notices are a form of GSA that may be entered into by parties that have a master agreement in place, which sets out the general terms and conditions of supply. While transaction notices have historically accounted for a relatively small proportion of gas sales, their use has increased over recent years.
- For the retailer invoice series, we have included invoices under GSAs that are for a term of three months or longer and that are for an annual contract quantity of at least 0.5 PJ per annum.
- Prices are based on invoices issued under all applicable GSAs in effect in a particular quarter (unless otherwise specified). This includes lower prices payable under a number of legacy GSAs that were entered into prior to recent changes to the East Coast Gas Market associated with the development of the LNG facilities in Queensland. The averages of prices presented in the invoiced prices series are therefore lower than the prices that have been agreed upon more recently. Some of the charts presented in this section include invoiced prices for GSAs that were entered into since July 2016, which are more comparable to recently agreed prices.

3.3.1. Gas prices paid to producers under GSAs

Chart 3.1 shows the quantity weighted average¹⁰¹ of quarterly gas prices that gas buyers in the East Coast Gas Market paid to gas producers in the Surat/Bowen¹⁰², Cooper and Gippsland/Otway/Bass¹⁰³ basins throughout 2015–2018. Invoiced prices are allocated to individual basins on the basis of the gas delivery points specified in invoices.

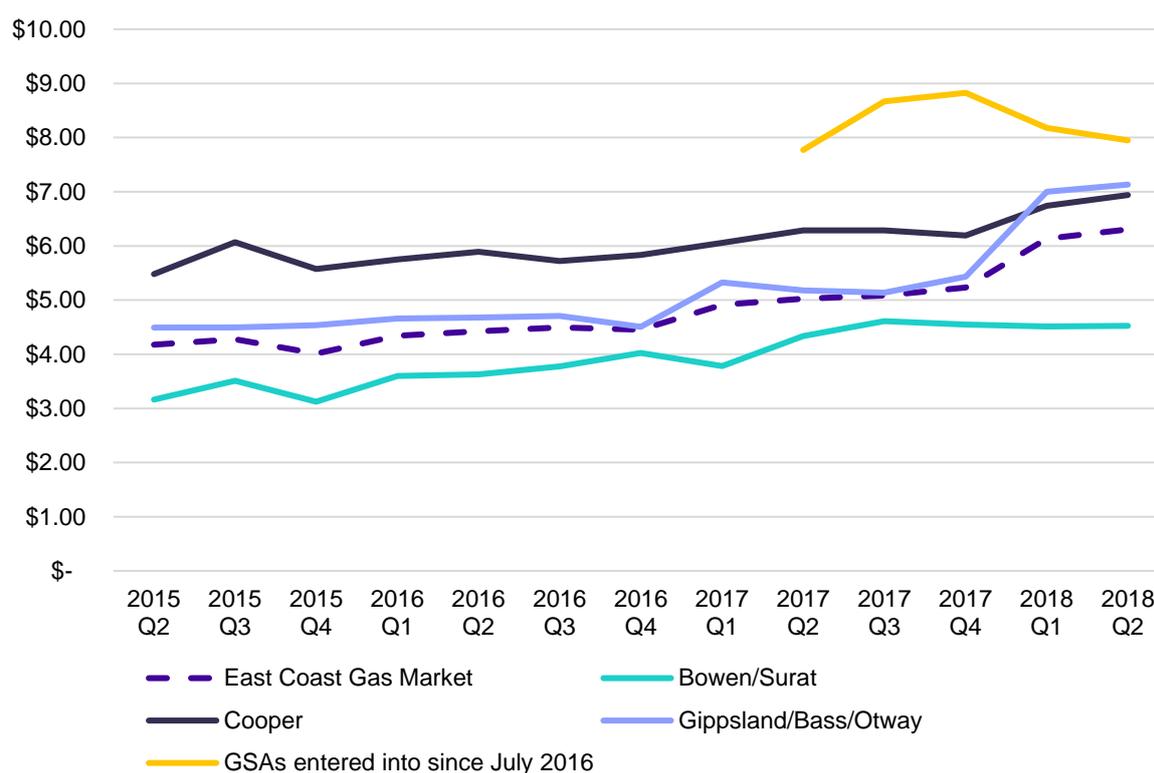
As in previous reports, we have included a separate line to show prices paid under more recent GSAs. For this purpose, we have included only GSAs entered into since July 2016. As this is a different cut-off date to that used in previous reports, these averages are not directly comparable to the averages in those reports.

¹⁰¹ As noted earlier, prices in this section are calculated on the basis of quantity weighted averages. The weights used in the calculation are based on the quantities of gas invoiced in the relevant period.

¹⁰² The Surat/Bowen basin price reflects producers that are capable of supplying gas to Wallumbilla.

¹⁰³ Due to the small number of producers in the Otway, Bass and Gippsland basins, a single average price has been calculated to represent the prices charged by the producers in these basins.

Chart 3.1: Average gas commodity prices invoiced by producers (\$nominal/GJ)



Source: ACCC analysis of information provided by producers.

Note: Average prices for the Cooper and Bowen/Surat basins differ slightly from those shown in the ACCC's April 2018 interim report. This is due to a reallocation of some invoices between these basins based on new information.

Chart 3.1 shows that the averages of prices paid across the East Coast Gas Market have continued to increase into 2018. The averages of prices were 51 per cent higher in Q2 2018 than they were in Q2 2015, increasing from \$4.18/GJ to \$6.30/GJ over this period.

Notably, the average of prices paid in the south-eastern basins (that is, Gippsland, Bass and Otway) increased by 29 per cent from Q4 2017 to Q1 2018. This is due to a number of relatively low-priced legacy GSAs expiring at the end of 2017, and several newer, higher-priced GSAs commencing supply at the start of 2018.

As discussed in section 2.10, conventional sources of gas in the Southern States have historically produced some of the cheapest gas in the east coast and this has been reflected in historical prices paid to southern producers. However, as discussed in sections 3.4 and 3.7 below as well as in our previous reports, prices offered and agreed for gas supply from these producers are significantly higher than historical levels. As chart 3.1 shows, the averages of prices paid in the Gippsland, Bass and Otway basins in the first half of 2018 were among the highest prices paid in the East Coast Gas Market.

As noted above, chart 3.1 contains prices paid under a number of legacy GSAs agreed upon when market conditions were substantially different. Prices from more recent GSAs, entered into since July 2016, have been separately marked on the chart. In Q2 2018, the average of prices paid to producers under these recent GSAs was \$7.95/GJ, compared to the average of prices paid to all the producers across the East Coast Gas Market of \$6.30/GJ – a 26 per cent difference.

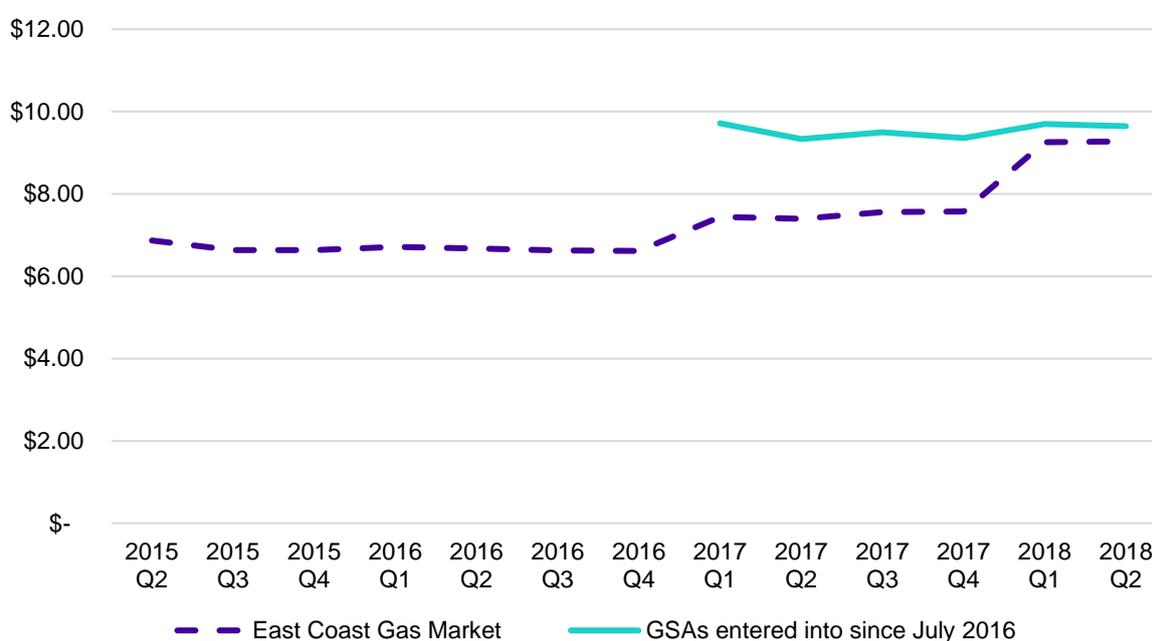
It should be noted that the increase in the average of invoiced prices observed under the recent GSAs over 2017 reflects an increase in oil prices, to which some of the prices under these agreements are linked.

3.3.2. Gas prices paid by C&I gas users to retailers under GSAs

Chart 3.2 shows the quantity-weighted average of prices that C&I gas users across the East Coast Gas Market paid to retailers in the period Q2 2015 – Q2 2018, separately presenting the prices paid under more recent GSAs entered into since July 2016.

The quantity-weighted averages have been calculated using prices specified in invoices. For 2015 and 2016, invoices under GSAs that were for a total annual contract quantity of at least 1 PJ are included. From 2017, the series is expanded to include GSAs that were for a total annual contract quantity of at least 0.5 PJ.

Chart 3.2: Average gas commodity prices invoiced by retailers to C&I Gas users (\$nominal/GJ)



Source: ACCC analysis of information provided by retailers.

Note: Average gas commodity prices up to 31 December 2016 are for GSAs with annual quantities of at least 1 PJ; from 1 January 2017, average gas commodity prices are for GSAs with annual quantities of at least 0.5 PJs.

From Q2 2015 to Q2 2018, the average of invoiced prices paid by C&I gas users to retailers increased by 35 percent, from \$6.87/GJ to \$9.27/GJ.

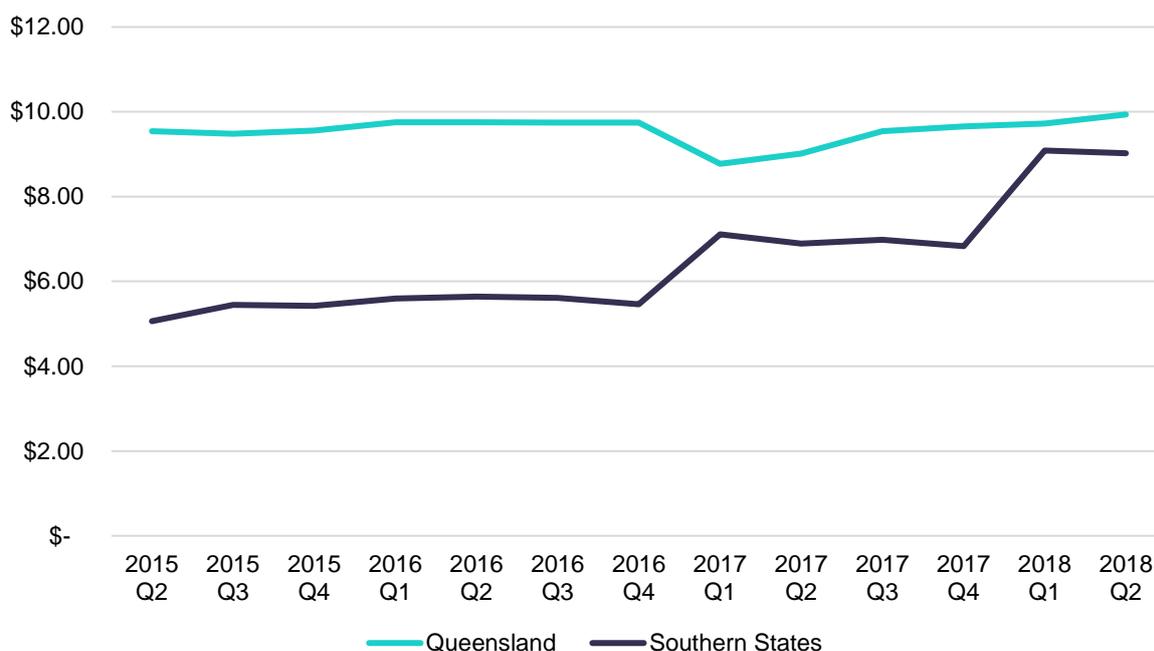
There was a notable increase between Q4 2017 and Q1 2018, during which the average retail price charged to C&I gas users rose from \$7.58/GJ to \$9.25/GJ, a 22 per cent increase.

The increase between these two quarters is due to a number of relatively low-priced older GSAs expiring at the end of 2017, and several newer, higher-priced GSAs commencing at the start of 2018. As noted in section 3.4 below as well as in our previous reports, most of the prices offered by retailers during the first half of 2017 exceeded \$10/GJ and some were over \$20/GJ. Although very few of these offers were accepted by C&I gas users at the time, some GSAs were entered into during this period. The increase in prices from Q4 2017 to Q1 2018 is particularly pronounced due to the high prices that were agreed to in early 2017.

In Q2 2018, the average of prices paid by C&I gas users to retailers under recent GSAs (\$9.65/GJ) was 4 per cent higher than the average of prices paid by C&I gas users to retailers under all GSAs (\$9.27/GJ). The small difference indicates that the Q2 2018 average invoiced price is closer to current market prices, due to the expiration of several lower-priced GSAs in December 2017.

Chart 3.3 breaks down the quantity-weighted average of prices paid by C&I gas users in Queensland and the Southern States.¹⁰⁴

Chart 3.3: Average gas commodity prices invoiced by retailers to C&I gas users, by region (\$nominal/GJ)



Source: ACCC analysis of information provided by retailers.

Note: Average gas commodity prices up to 31 December 2016 are for GSAs with annual quantities of at least 1 PJ; from 1 January 2017, average gas commodity prices are for GSAs with annual quantities of at least 0.5 PJs.

Over the past three years, C&I gas users in the Southern States have experienced a 78 per cent increase in the average of retail prices – from \$5.06/GJ in Q2 2015 to \$9.02/GJ in Q2 2018.

Chart 3.3 shows that from Q4 2017 to Q1 2018, the average of prices paid by C&I gas users to retailers in the Southern States increased by 33 per cent, with Victorian C&I gas users in particular experiencing a price rise of 41 per cent over this period. The increase was caused by the expiry of several lower-priced GSAs in Q4 2017, which rolled over into higher-priced GSAs in Q1 2018. C&I gas users in Queensland, however, paid prices consistent with a three-year average of just under \$10/GJ. The brief drop in prices paid by Queensland C&I gas users shown between Q4 2016 and Q1 2017 was caused by the expiry of some legacy GSAs. It should be noted, however, that the average of retailer prices for Queensland are based on a small number of GSAs relative to the Southern States.

Chart 3.3 demonstrates that the 22 per cent quarterly increase in the average of prices paid by C&I gas users to retailers across the East Coast Gas Market at the start of 2018 (as shown in chart 3.2 above) was driven by an increase in prices paid by gas users in the

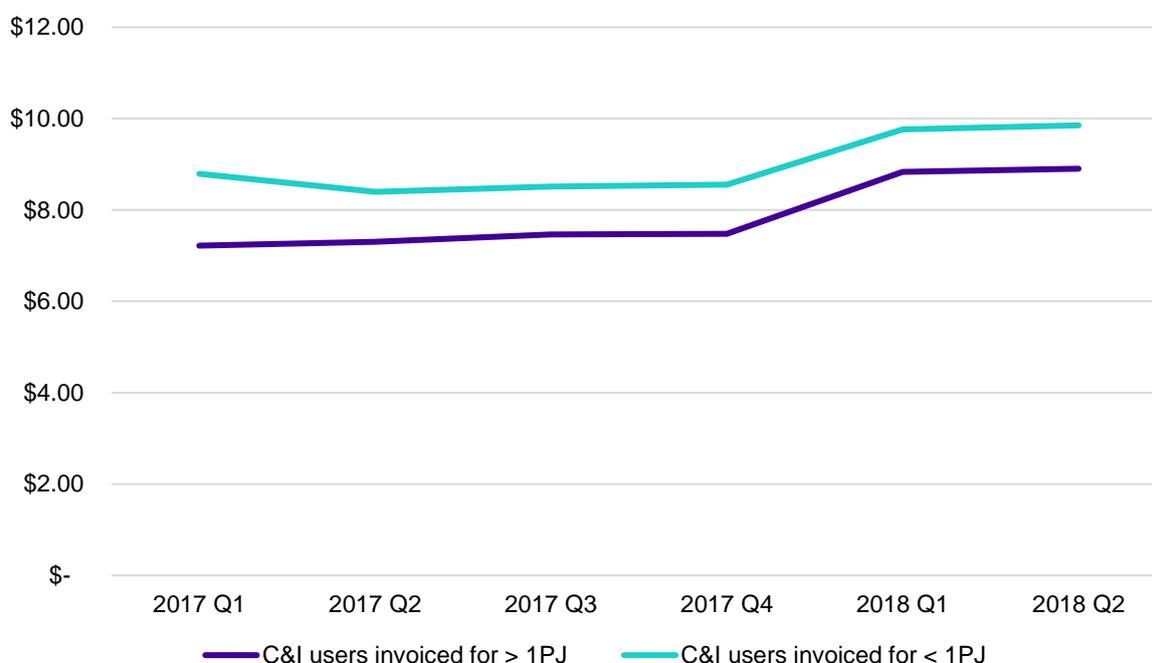
¹⁰⁴ The Southern States include Victoria, NSW, ACT, Tasmania and South Australia.

Southern States, and particularly in Victoria. Many of the higher prices paid in 2018 were under GSAs executed during 2017. These gas users appear to have been most affected by the exceptional market conditions that prevailed during 2017 which, as noted above, saw retailers offering very high prices.

The chart also shows that C&I users in Queensland have paid higher prices to retailers than users in the Southern States over the past 3 years, although this gap has reduced from \$4.48/GJ in Q2 2015 to \$0.91/GJ in Q2 2018.

Chart 3.4 shows the prices paid to retailers by C&I gas users that purchased larger quantities compared to the prices paid by C&I gas users that purchased smaller quantities. For the purpose of this chart, C&I gas users across the East Coast Gas Market were classified into one of two groups, depending on whether they were invoiced for less than, or greater than, one petajoule (PJ) of gas per annum. For C&I gas users that were invoiced for gas across a number of sites, they were classified based on the total quantity invoiced across all sites.

Chart 3.4: Average gas commodity prices invoiced by retailers, by quantity invoiced to C&I gas users (\$nominal/GJ)



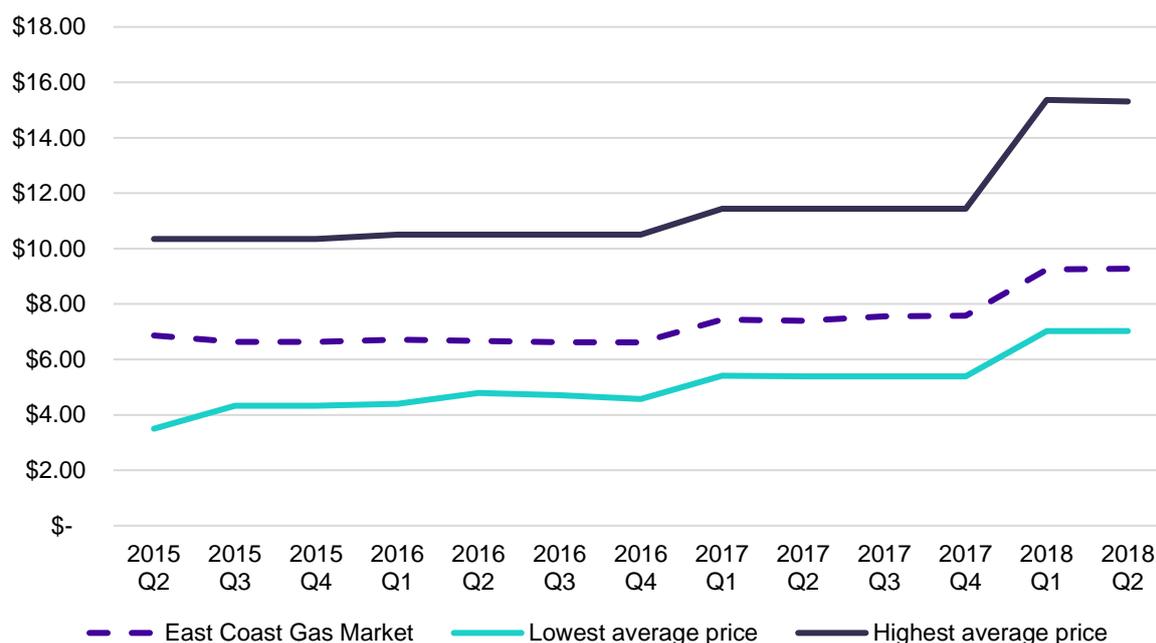
Source: ACCC analysis of information provided by retailers.

Over the past 12 months, C&I gas users that were invoiced for less than one PJ per annum paid an average of 12 per cent more than gas users that were invoiced for more than 1 PJ per annum. The difference ranged between \$0.93–1.08/GJ. It may be that larger gas users may have more bargaining power when negotiating GSAs with retailers, due to the total value that their demand represents.

Chart 3.5 shows the highest and lowest quarterly averages of prices paid by C&I gas users to retailers/aggregators.¹⁰⁵

¹⁰⁵ To develop chart 3.5 we calculated the quarterly averages of prices invoiced to each C&I gas user by all retailers/aggregators that supplied the user in the quarter. The top line in the chart represents the highest quarterly average price paid by a C&I gas user, while the bottom line represents the lowest quarterly average.

Chart 3.5: Highest and lowest quarterly averages of gas commodity prices invoiced by retailers/aggregators to individual C&I gas users (\$nominal/GJ)



Source: ACCC analysis of information provided by retailers.

Note: Average gas commodity prices up to 31 December 2016 are for GSAs with annual quantities of at least 1 PJ; from 1 January 2017, average gas commodity prices are for GSAs with annual quantities of at least 0.5 PJs.

Chart 3.5 shows that there is a significant range in the prices paid by C&I gas users to retailers relative to the average across the east coast. The chart shows that, between Q2 2015 and Q4 2017, the gap between the highest and lowest prices paid to retailers was relatively constant at around \$6/GJ. However, in 2018 this gap widened to over \$8/GJ.

Notably, the highest price paid by a C&I gas user to a retailer in 2018 was over \$15/GJ, under a GSA that was executed during 2017. This demonstrates that, while most of the very high priced offers from retailers during 2017 were rejected by gas users, some were accepted and the resulting GSAs are contributing to the significant increase in the averages of prices paid across the east coast to retailers at the start of 2018.

3.4. Prices offered for gas supply in 2019

This report marks the third time we have reported on offers made and bids received by suppliers in the East Coast Gas Market for gas supply in 2019. For this report, we extend our previous coverage with the addition of information on offers made and bids received by gas suppliers between 25 April and 30 August 2018 for gas supply in 2019.

Box 3.3 below sets out the ACCC’s approach to reporting on offers and bids.

Box 3.3: Approach to reporting on offers and bids

The information in this box should be read in conjunction with information in box 3.1. The following also applies to the analysis of offers and bids in this section.

- We have only included in our analysis those offers and bids that are sufficiently developed to contain clear indications of the key terms of price, quantity and supply start and end dates.
- The gas prices have been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (oil prices, LNG prices, foreign exchange rates and CPI) based on the expectations for those variables at the time of the offer or bid.¹⁰⁶

Analysis of offer and bid pricing throughout this chapter is intended to provide an indication of price trends over time. As explained in box 3.1, the prices of individual offers and bids are not all directly comparable, as they can differ in non-price aspects. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil) or, in the case of GPGs, conditions in the electricity market.

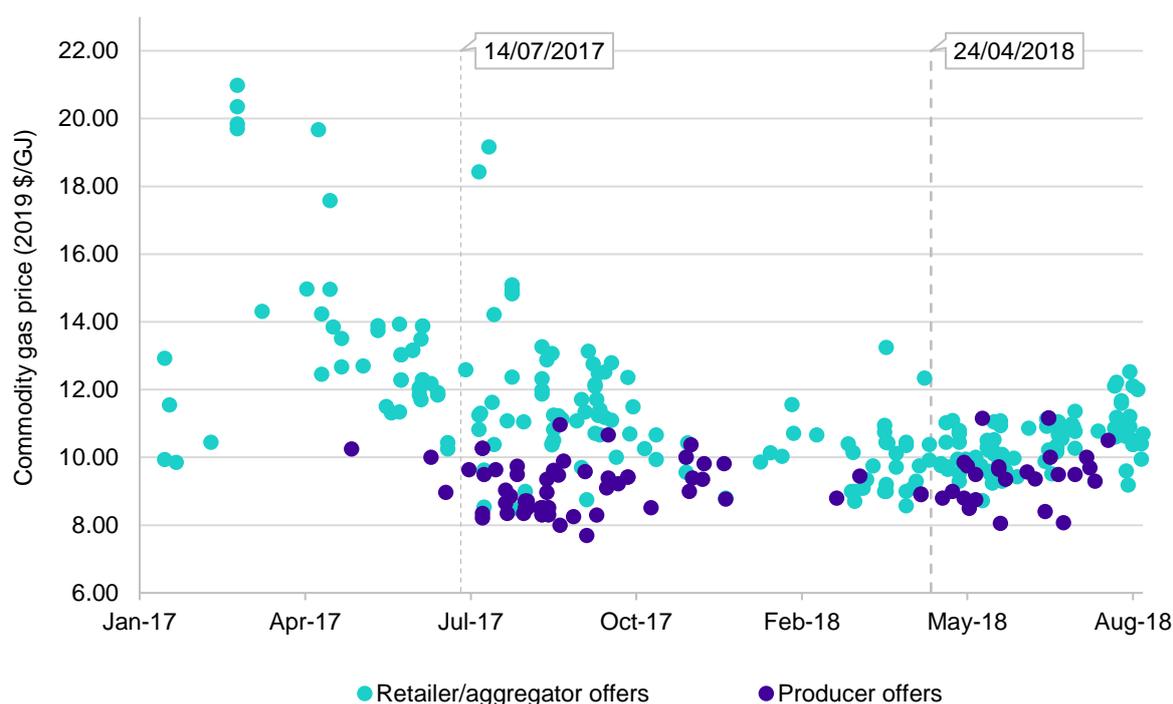
Prices over time: offers for gas supply in 2019

Chart 3.6 below shows the gas commodity prices included in offers made by retailers/aggregators and producers over the period from 1 January 2017 to 30 August 2018 to all gas buyers for supply in 2019. It should be noted that not all price offers in the chart (and those discussed in this section) are for unique combinations of seller and buyer. That is, some offers may reflect follow up offers that were made by the same supplier to the same buyer after a previous offer did not result in a GSA. The chart is intended to give an indication of how the level of price offers in the East Coast Gas Market has evolved since the start of 2017.

¹⁰⁶ In all estimates of 2019 offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate for 2019 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 for 2019 is equal to the average price of 2019-dated futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japanese Customs Cleared (JCC) crude oil price for 2019 is derived using the expected Brent crude oil price as a proxy.
- The expected Japan Korea Marker (JKM) LNG price for 2019 is equal to the average price of 2019-dated futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5% thereafter.

Chart 3.6: Gas commodity price offers for 2019 supply in the East Coast Gas Market



Source: ACCC analysis of offer and bid information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

In the ACCC's July 2018 report, we reported that most offers made in the six months to 24 April 2018 fell within the high-\$8 to \$11/GJ range. The trend in offer prices during that period was flat, following a downward trend through the middle of 2017 as prices came down from their early-2017 peak. For this report, the ACCC has obtained information on offers made by suppliers in the subsequent four month period to 30 August 2018.

Chart 3.6 shows that most offers made in the four months to 30 August 2018 were priced in the \$9 to \$12/GJ range. There was a higher proportion of offers priced at or above the mid-\$10 level compared with the preceding six months, with relatively few offers being made below \$10 by the end of the period. Most offers made in the month of August were priced at or above the mid-\$10 level, including several above \$12. The vast majority of offers made in August were by retailer/aggregators. As reported previously by the ACCC, retailer/agggregator offer prices have generally been higher than producer offer prices.¹⁰⁷

A greater prevalence of offers priced at or above the mid-\$10 level in recent months may reflect rising expectations for export parity prices for 2019. Expectations for 2019 Asian LNG netback prices at Wallumbilla have increased significantly over recent months (see section 3.5 below for detailed analysis of domestic offer prices compared to LNG netback price expectations).

Recent offer prices remain lower than those seen in the first half of 2017. This may reflect a less uncertain gas supply-demand outlook for 2019 following commitments by LNG producers to make additional quantities of gas available into the domestic market. In addition, the ACCC's monitoring and reporting of prices may be reducing information

¹⁰⁷ ACCC, *Gas Inquiry 2017-2020 Interim Report*, July 2018, p. 43.

asymmetry in negotiations and, in so doing, facilitating more effective negotiations between sellers and buyers.

Recent offers and bids for gas supply in 2019

This section discusses recent offers made and bids received by producers and retailers/aggregators.

Table 3.1 presents analysis of recent offers made and bids received by gas producers for gas supply to all buyers in 2019. The table compares the offers made and bids received in the period between 25 April 2018 and 30 August 2018 with the preceding six months.

Table 3.1: Recent offers made and bids received by producers for gas supply in 2019 (all buyers)¹⁰⁸

25 October 2017 – 24 April 2018	Offers	Bids
Number of offers or bids	13	47
Gas commodity price range (\$/GJ)	8.52 – 10.37	7.25 – 10.62
Average gas commodity price (\$/GJ)	9.04	8.43
25 April 2018 – 30 August 2018	Offers	Bids
Number of offers or bids	26	44
Gas commodity price range (\$/GJ)	8.05 – 11.16	6.41 – 10.50
Average gas commodity price (\$/GJ)	9.78	8.98

Source: ACCC analysis of offer and bid information provided by suppliers.

Table 3.1 shows an increase in the average of prices for both offers made and bids received by producers between 25 April 2018 and 30 August 2018, compared with the preceding six months. The average of offer prices increased by \$0.74/GJ, compared with an increase in the average of bid prices of \$0.55/GJ. This expanded the spread between the average of offer and bid prices to \$0.80/GJ, up from \$0.61/GJ in the preceding six months.

The increased spread between the average of offer and bid prices appears to be reflected in the outcomes of bids received by producers between 25 April 2018 and 30 August 2018. Only 3 of the 44 bids were accepted by 30 August 2018. In contrast, producers rejected 23 of the bids. Of the balance, most were superseded by subsequent negotiations including counter offers by producers and revised bids by buyers.

In the ACCC's July 2018 report, we observed that there were relatively few offers made by producers in the early months of 2018, but noted that producers were expected to be more active in making offers for gas supply in 2019 as the year progressed. The offer information collected by the ACCC shows that in the four months between 25 April 2018 and 30 August 2018 the number of offers made by producers was double that of the preceding six months.

In the July 2018 report, we reported a relatively high number of bids compared to the number of offers made by producers in the early months of 2018, as a result of several

¹⁰⁸ Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 12 months duration and annual quantities of at least 0.5 PJ.

producers running Expression of Interest (EOI) gas sales processes.¹⁰⁹ This has continued, with several producers running EOI processes between 25 April 2018 and 30 August 2018. The number of bids received by producers during that period was almost double the number of offers made.

Table 3.2 presents analysis of offers made and bids received by gas retailers/aggregators for gas supply in 2019. The analysis in this table is limited to offers made to, and bids received from, C&I gas users. The table compares the offers made and bids received in the period between 25 April 2018 and 30 August 2018 with the preceding six months.

Table 3.2: Recent offers made and bids received by retailers/aggregators for gas supply in 2019 (C&I gas users)¹¹⁰

25 October 2017 – 24 April 2018	Offers	Bids
Number of offers or bids	35	6
Gas commodity price range (\$/GJ)	8.57 – 12.34	7.50 – 12.59
Average gas commodity price (\$/GJ)	9.68	8.66
25 April 2018 – 30 August 2018	Offers	Bids
Number of offers or bids	80	< 5
Gas commodity price range (\$/GJ)	8.72 – 12.53	8.70 – 9.72
Average gas commodity price (\$/GJ)	10.28	9.15

Source: ACCC analysis of offer and bid information provided by suppliers.

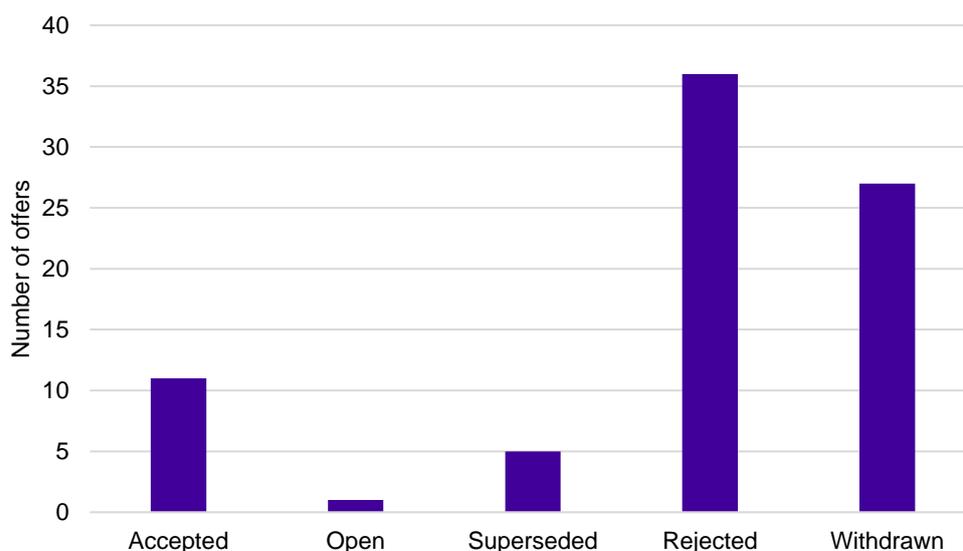
Table 3.2 shows that although the number of offers made by retailers/aggregators to C&I gas users in the period between 25 April 2018 and 30 August 2018 more than doubled compared with the preceding six months, the average of prices for those offers increased by \$0.60/GJ. The upper and lower ends of the offer price range also increased, but to a lesser extent.

Chart 3.7 below shows the distribution of responses to the 80 offers made by retailers/aggregators to C&I gas users between 25 April 2018 and 30 August 2018.

¹⁰⁹ ACCC, *Gas Inquiry 2017-2020 Interim Report*, July 2018, p. 42.

¹¹⁰ Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 12 months duration and annual quantities of at least 0.5 PJ.

Chart 3.7: Distribution of C&I gas users' responses to offers made by retailers/aggregators in the period between 25 April 2018 and 30 August 2018



Source: ACCC analysis of offer and bid information provided by suppliers.

Chart 3.7 shows that the vast majority of offers made by retailers/aggregators to C&I gas users between 25 April 2018 and 30 August 2018 were either rejected or expired without response from the user. This contrasts with the very small number of offers that were superseded by a user's counter bid or by a revised offer. A number of users have sought Requests for Proposal (RFPs) from multiple suppliers simultaneously in competitive tender-type processes. This may explain the high number of rejected and expired offers relative to the number of superseded offers, because the approach allows the user to assess all available offers at the same time and eliminate all but the most competitive. Notably, our survey of C&I gas users' recent experiences in the market (set out in section 3.6) revealed that a majority of C&I gas users ranked a lack of competition among suppliers in their top three concerns. The high proportion of rejected and expired offers is consistent with C&I users viewing relatively few of the offers they received from retailers/aggregators as being competitive.

In the ACCC's July 2018 report, we observed that the average of offer prices made by retailers/aggregators to C&I gas users were generally higher than for offers made by producers. We noted that this may reflect the inclusion of retailer-specific costs and margins as well as the value of non-price terms. We also noted that we had begun working to better understand the value components that make up retail gas commodity prices and that we would be examining retailers' costs and margins more broadly (see chapter 5 of this report, in which we analyse retailers' costs and margins over the four year period from 2014 to 2017). Although the trend has persisted, the gap narrowed slightly to \$0.50/GJ for the period between 25 April 2018 and 30 August 2018, compared with a difference of about \$0.64/GJ during the preceding six months.

As discussed in the introduction to this chapter, while construction of the NGP has created scope for Northern Territory suppliers to begin making offers to, and receiving bids from, buyers in the East Coast Gas Market, these have been excluded from table 3.1 and table 3.2. In the period between 25 October 2017 and 30 August 2018, Northern Territory suppliers made a small number of offers and received a small number of bids at lower commodity gas prices compared to those reported in table 3.1 and table 3.2. However, once the cost of transportation from the Northern Territory is included the offers from, and bids to,

the Northern Territory suppliers become broadly consistent with the prices of offers made and bids received by east coast suppliers as reported in table 3.1 and table 3.2.

3.5. Prices offered for gas supply in 2019 compared to contemporaneous LNG netback price expectations and production cost

This section compares prices offered for 2019 supply in the East Coast Gas Market in each month between January 2017 and August 2018 against contemporaneous expectations of 2019 LNG netback prices and estimated costs of gas production.

For this analysis, LNG netback prices have been calculated based on market expectations, at relevant points in time, of Asian LNG spot prices over the course of 2019.¹¹¹ Costs of production used for comparison reflect the estimated breakeven gas price of the marginal supplier of gas in the East Coast Gas Market for 2019.

Sections 3.5.1 and 3.5.2 set out why we have used these measures of LNG netback price and cost of production in this analysis. Section 3.5.3 presents the findings of our comparison for prices offered in Queensland and the Southern States. Finally, section 3.5.4 discusses how expected 2019 LNG netback prices have changed over recent months.

3.5.1. LNG netback prices used for comparison

As discussed in our previous reports, Asian LNG spot netback prices are a key factor influencing domestic gas prices under current market conditions.

The ACCC has therefore used LNG netback prices based on Asian LNG spot prices to compare against prices offered in the East Coast Gas Market. In particular, given that the decisions facing LNG producers regarding the sale of excess gas are made over the short-run, the ACCC has used short-run LNG netback prices (which, as discussed below, account for the short-run marginal costs of LNG production and transportation). For assessing domestic offers of longer durations, other LNG price markers, such as short-term and medium-term (for example, 3–5 year) multi-cargo LNG contracts, may be relevant as a basis for netback prices.

The ACCC considers that the relevant LNG netback price against which to compare prices offered for future supply in the domestic market is a forward LNG netback price—specifically, one that is based on market expectations of what Asian LNG spot prices will be during the relevant period of supply. Further, in the context of negotiations for future domestic gas supply, the forward LNG netback prices estimated at the time of negotiation are most relevant. This is because these expectations at the time of negotiation provide the best indicator of what the supplier expected, at that time, to be its opportunity cost of supplying gas to the domestic market over the proposed period.

The LNG netback prices used for the analysis in this section are determined using the method and assumptions used for the LNG netback price series published on the ACCC's website, as at the time of publication of this report (see box 3.4 for a description of the LNG netback price series).

¹¹¹ Where the phrase 'expected LNG netback prices' or similar phrases are used in this report, we refer to LNG netback prices calculated on the basis of Asian spot LNG futures prices, which represent LNG futures market participants' collective expectations of Asian spot LNG prices for given futures contract months. The 'expected LNG netback prices' shown in this report do not represent an ACCC forecast of international or domestic gas prices.

Box 3.4: ACCC LNG netback price series

As discussed in our previous reports,¹¹² a key problem facing C&I gas users in the East Coast Gas Market following the linking of the domestic gas market to the international LNG market has been the lack of an indicative price of gas. The lack of readily available pricing information and limited shared understanding of the factors driving gas prices (and how they are calculated) has, over recent years, impaired competitive bargaining and favoured large incumbent suppliers in gas price negotiations.

In October 2018, the ACCC commenced publishing an LNG netback price series on its website in recognition of the important role that LNG netback prices play in shaping gas prices in the East Coast Gas Market and the need to improve gas price transparency. The series includes:

- historical monthly LNG netback prices at Wallumbilla, dating back to January 2016, based on a measure of historical Asian LNG spot prices, and
- forward monthly LNG netback prices at Wallumbilla, extending to the end of the following calendar year, based on a measure of expectations of future Asian LNG spot prices.

Historical LNG netback prices will be updated on the ACCC website once a month, and forward LNG netback prices will be updated twice a month, throughout the ACCC's Inquiry.

The ACCC also published a *Guide to the LNG netback price series* that outlines the ACCC's method for calculating the prices in the series and how the series can be used in practice, as well as a spreadsheet that shows the step-by-step calculation of LNG netback prices with transparent and adjustable inputs and assumptions.

The LNG netback price series can be used by gas buyers and other parties to, for example, observe historical trends of LNG netback prices at Wallumbilla and estimate an indicative reference price of gas at particular locations in the East Coast Gas Market for future periods of gas supply.

Over the course of the Inquiry, the ACCC intends to publish additional information on its website to accompany the LNG netback price series to further improve gas price transparency, including information on transportation charges and estimates of gas production costs. The ACCC will monitor the effectiveness of the LNG netback price series and accompanying materials, and will make a recommendation at the conclusion of the inquiry on whether the price series should continue.

As explained in the ACCC's *Guide to the LNG netback price series*,¹¹³ the calculation of forward Asian LNG spot netback prices requires an indicator of market expectations of what Asian LNG prices will be during the relevant future period. For this, the ACCC has used futures prices of the Japan Korea Marker (JKM) quoted by the Intercontinental Exchange (ICE).

The domestic offers analysed in this section are all for gas supply over the entire 2019 calendar year. Therefore, for the purpose of comparison, we calculated an average LNG netback price that an LNG exporter would expect to receive, at a minimum, to be indifferent between selling the gas to the domestic buyer over the entire 2019 calendar year and selling cargoes on the Asian LNG spot market over the entire 2019 calendar year.

For example, the average LNG netback price for 2019 that an LNG producer would have expected to receive, at a minimum, in July 2017 is calculated as follows:

- JKM futures prices were obtained for each month of 2019 that were quoted by ICE on each day during July 2017.
- The monthly 2019 JKM futures prices were converted into LNG netback prices at Wallumbilla by:

¹¹² ACCC, *Gas Inquiry 2017-2020 Interim report*, April 2018, pp. 33-34.

¹¹³ ACCC, *Gas Inquiry 2017-2020: Guide to the LNG netback price series*, <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series>.

- converting the prices from US\$/MMBtu into A\$/GJ using contemporaneous exchange rates, and
- subtracting the short-run marginal costs of shipping, liquefaction¹¹⁴ and transportation.¹¹⁵
- These monthly LNG netback prices were averaged to arrive at an average LNG netback price for 2019 expected on each day during July 2017.
- The daily LNG netback prices were averaged to arrive at an average LNG netback price for 2019 expected during July 2017.

For charts 3.8 and 3.9 below, the expected 2019 LNG netback prices at Wallumbilla were calculated in this way for each month between January 2017 and August 2018.

3.5.2. Cost of gas production used for comparison

As discussed in section 2.10, the ACCC engaged Core Energy (Core) to develop detailed and up-to-date estimates of the gas production costs currently facing producers in the East Coast Gas Market. For individual supply regions across the east coast, Core estimated both full lifecycle costs of production and forward costs of production for 2P reserves as at 31 December 2017.

The lifecycle costs of production reflect the breakeven gas price for a supply region's entire cash flows over lifetime production, while forward costs reflect the breakeven gas price for a supply region's future cash flows over future production volumes.

As noted above, the analysis in this section compares domestic price offers to short-run LNG netback prices given the short-run nature of the decisions being made by LNG producers in respect of the sale of excess gas expected over 2019. Similarly, for the purpose of comparing price offers for 2019 supply with production costs, we use forward costs, since over the short-term, producers may continue producing gas as long as they expect to achieve a sufficient rate of return on the associated future investment.

For charts 3.8 and 3.9 below, the level of forward production costs the ACCC has used for comparison is that of the marginal source of supply on the east coast—that is, the supply region connected to the East Coast Gas Market with the highest forward cost—where material uncontracted reserves are expected to be in production in 2019. Based on Core's forward cost estimates, the highest cost of supply regions that meet this criteria are the Middle Surat and Roma Shelf supply regions, which Core estimates to include 9260 PJ of 2P reserves with a forward production cost of \$5.55/GJ.

The cost of the marginal source of production in the East Coast Gas Market is an important factor that can influence domestic gas prices. As discussed in box 3.5 below, depending on the level of LNG netback prices at Wallumbilla and the level of competition among suppliers in the Southern States, the marginal cost of gas production may determine the range within which domestic gas prices would be expected to fall in gas price negotiations in the Southern States. In any case, the marginal cost of gas production represents the floor price in any gas supply negotiation.

¹¹⁴ We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from the LNG producers in Queensland.

¹¹⁵ We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from the LNG producers.

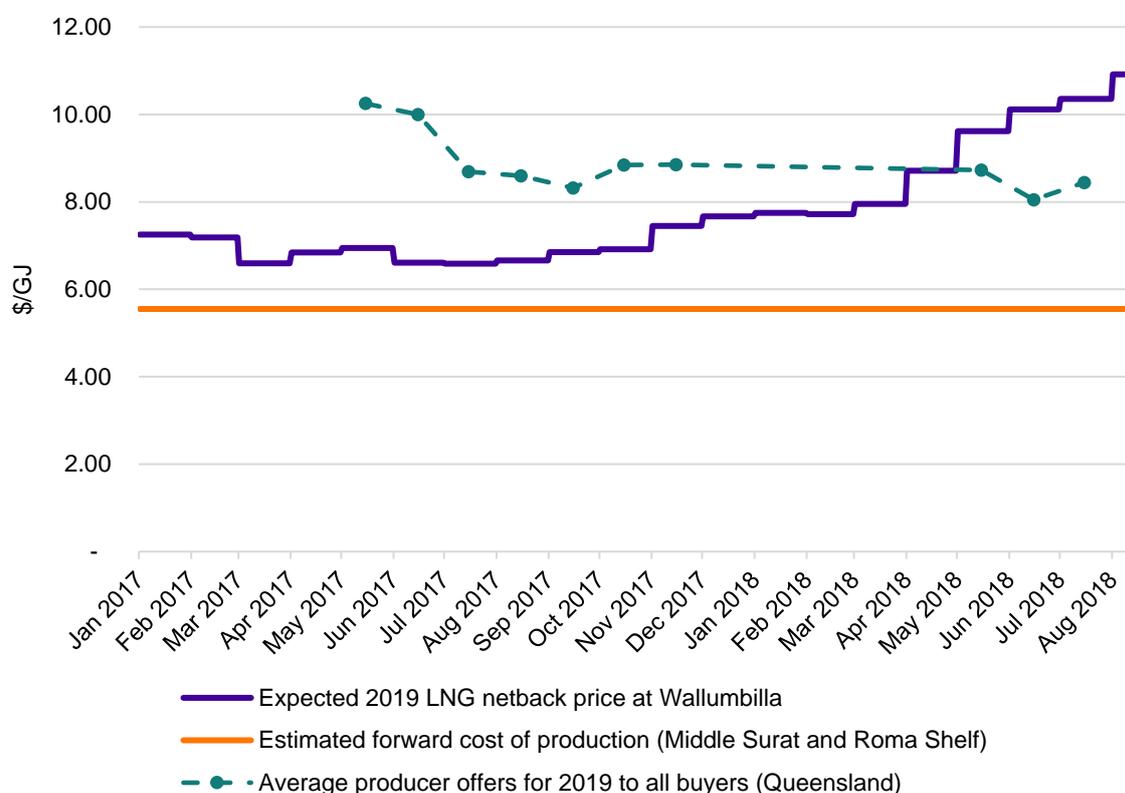
3.5.3. Domestic price offers for 2019 supply have moderately increased with LNG netback prices

This section compares prices offered for 2019 supply in Queensland and the Southern States to contemporaneous expectations of 2019 LNG netback prices and costs of production.¹¹⁶

Queensland

Chart 3.8 below shows 2019 LNG netback prices at Wallumbilla that were expected during each month between January 2017 and August 2018. Against these expected 2019 LNG netback prices, chart 3.8 shows quantity-weighted averages of prices offered by Queensland producers in corresponding months where there were prices offered.¹¹⁷ The price averages shown in this chart are derived using the same information used in our analysis of 2019 prices in section 3.4 above, but for the purpose of this chart the prices offered in each month are averaged.

Chart 3.8: Averages of monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (Queensland)



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

Note: JKM futures prices quoted by ICE before June 2017 related to futures contracts for the first half of 2019 only.
 Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components.
 Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

¹¹⁶ Prices reflected in the charts do not include offers for supply of gas produced in NT. Absence of data points for particular months for each series of offers indicates that there were insufficient offers made in those months.

¹¹⁷ The chart does not include offers from retailers/aggregators in Queensland due to the small number of offers made over the relevant period.

In the ACCC's July 2018 report, we compared offer prices with expectations of 2019 LNG netback prices from January 2017 up to the end of April 2018, over which netback prices materially increased. In the subsequent four month period to the end of August 2018, expected 2019 LNG netback prices continued to rise. Chart 3.8 shows that, while in April 2018 expected LNG netback prices averaged around \$8.70/GJ, in August 2018 they averaged around \$10.90/GJ. This was driven by an increase in expected Asian LNG spot prices over 2018—caused by a combination of factors including strong LNG demand over the middle of the year, numerous unexpected LNG supply disruptions, and increases in oil prices—as well as depreciation in the Australian dollar.¹¹⁸

Chart 3.8 shows that, while producer offers in Queensland during 2017 exceeded contemporaneous 2019 LNG netback price expectations, between May and July 2018 offers were below 2019 LNG netback prices expected at those times. Producer price offers over these months averaged between around \$8–8.70/GJ while expected netback prices averaged between around \$9.60–10.40/GJ over the same period. This may suggest that some producers were offering prices at a discount to expected netback prices—particularly in June 2018 when the averages of offer prices were over \$2/GJ below netback prices—and/or had different expectations about LNG netback prices at Wallumbilla at the times the offers were made.¹¹⁹

Notwithstanding that most producer offers in Queensland between April and August 2018 were priced below expected 2019 LNG netback prices, the averages of offer prices were significantly above Core Energy's estimated forward cost of production of the marginal source of supply in the east coast. For example, at its lowest point in June 2018, the average of offer prices was around \$2.50/GJ above the marginal forward cost of production, while the average of offer prices in May 2018 was over \$3/GJ higher than the marginal forward cost of production.

Average prices of offers were also significantly above the quantity-weighted average forward cost of production across all supply regions in Queensland, which based on Core's estimated costs of production and 2P reserves, is \$4.91/GJ. Further, the highest lifecycle cost of production of any Queensland supply region estimated by Core is \$6.80/GJ (for both Ironbark, the Middle Surat and Roma Shelf).

This shows that the averages of gas prices offered by Queensland producers to domestic gas buyers from January 2017 to August 2018 were well above Core's estimates of producers' forward and lifecycle breakeven costs of production. Not all of these offers were accepted by gas buyers. However, with Queensland producers expecting to receive a quantity-weighted average price of \$8.36/GJ for those offers that resulted in a GSA (as shown in table 3.3 below), a substantial margin is likely to be achieved by Queensland producers for supplying the domestic gas market in 2019.

Southern States

As explained in our previous reports, the ACCC has adopted a bargaining framework to analyse pricing outcomes in the Southern States.¹²⁰ Under this framework, the pricing dynamics in the Southern States are different from those in Queensland. Box 3.5 below explains the ACCC's bargaining framework and how it is used to assess prices offered in the East Coast Gas Market.

¹¹⁸ Australian Financial Review, 'LNG supply glut is "still coming"', 5 October 2018, <https://www.afr.com/business/energy/gas/lng-supply-glut-is-still-coming-20181005-h169w0>.

¹¹⁹ Producers' expectations at different points during mid-2018 about LNG netback price at Wallumbilla for 2019 may have differed from those estimated by the ACCC, since this was a period of significant volatility for JKM futures prices (see chart 3.10 below).

¹²⁰ ACCC, *Gas Inquiry 2017–20 – Interim Report*, September 2017, p. 69.

Box 3.5: ACCC bargaining framework

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 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 at Wallumbilla less the cost of transporting gas to Wallumbilla or the cost of production (whichever is higher).

Whether 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 balance 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. 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.¹²¹ 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.¹²²

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 marginal cost of production. The marginal cost of production therefore sets the floor price in any gas supply negotiation.

To meaningfully analyse the level of prices offered in a particular location in the Southern States using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location.

Chart 3.9 below shows the quantity-weighted averages of prices offered by suppliers in the Southern States between January 2017 and August 2018 compared to the range within which gas prices would be expected to fall using the bargaining framework set out in box 3.5.

The upper end of the range is the buyer alternative in Victoria which, as noted in box 3.5, is indicative of the highest price that would be expected to be offered in the Southern States under this bargaining framework. These prices are derived by taking expected 2019 LNG netback prices at Wallumbilla and adding indicative pipeline tariffs to Melbourne. 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:

¹²¹ This would depend on whether the buyer is able to acquire capacity on relevant pipelines over the period of supply, as well as the pipeline tariffs that are to be paid.

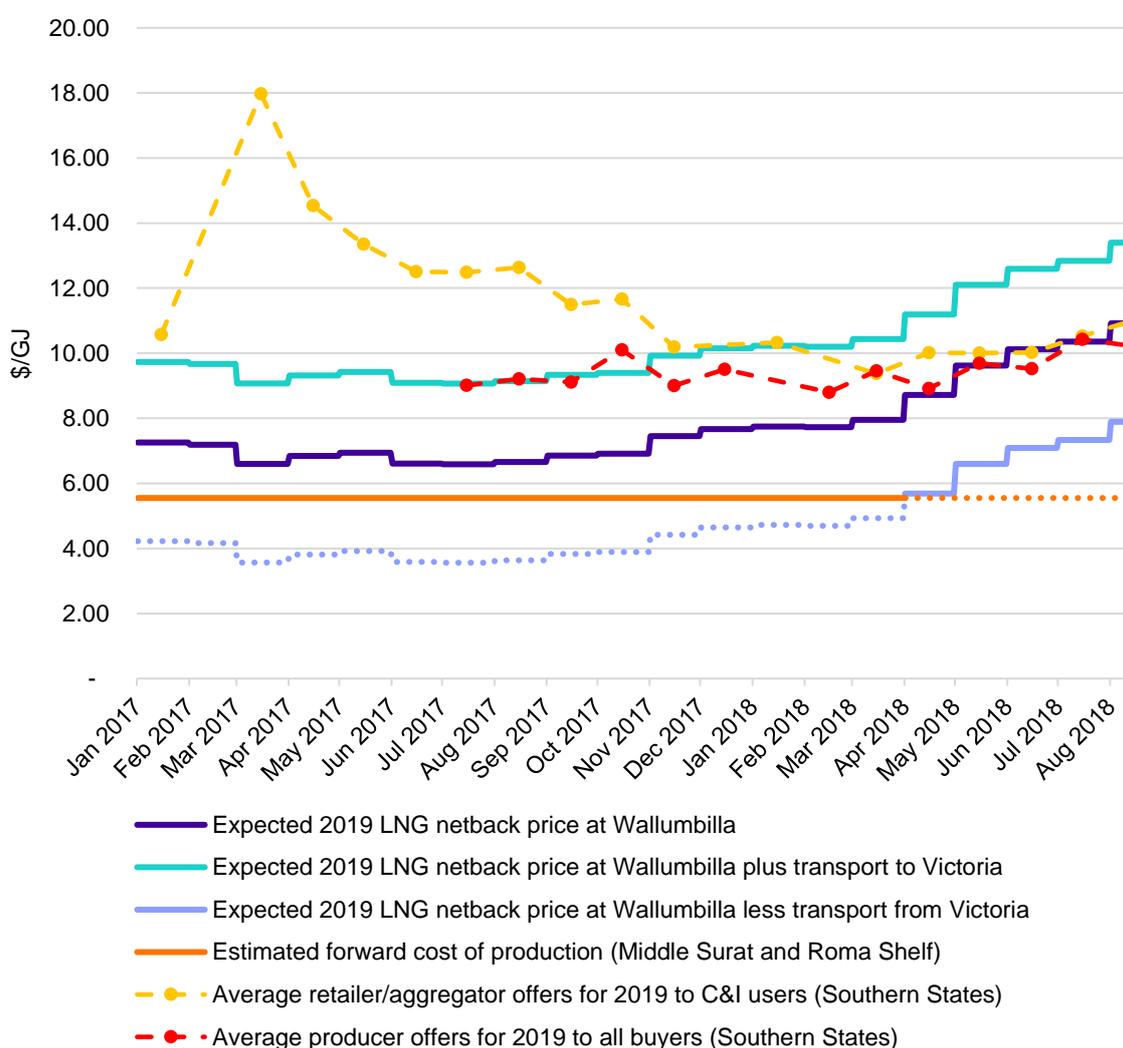
¹²² We note that prices offered to individual buyers may also be influenced by other factors, particularly non-price terms and conditions.

- expected 2019 LNG netback prices at Wallumbilla less indicative pipeline tariffs from Melbourne to Wallumbilla, and
- the cost of production of the marginal source of supply.

As discussed above, for this comparison, we use the estimated forward cost of production of the marginal source of east coast supply with material uncontracted reserves expected to be in production in 2019. Core Energy’s findings indicate that this is the Middle Surat and Roma Shelf supply region, with an estimated forward production cost of \$5.55/GJ.

However, we note that the LNG netback prices and buyer and seller alternative prices shown in chart 3.9 do not account for other factors that may influence prices offered to gas buyers, such as flexible non-price terms in GSAs and retailer costs and margins.

Chart 3.9: Averages of monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (Southern States)



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

Note: JKM futures prices quoted by ICE before June 2017 related to futures contracts for the first half of 2019 only.
 Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components.
 Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

In the ACCC's July 2018 report, we found that the averages of prices offered by southern producers in mid to late 2017 were around Victorian buyer alternative prices, and that the averages of prices offered by retailers/aggregators to C&I gas users in the Southern States were, for most of 2017, well in excess of Victorian buyer alternative prices. We observed that retailer pricing behaviour during 2017 indicated that the gas market was not functioning effectively, and that it would have been more economic for C&I gas users to purchase gas directly from southern producers or to transport gas from Queensland.

However, as market conditions improved over the course of 2017 and up to April 2018, prices offered by retailers/aggregators in the Southern States fell, while producer offers remained relatively stable. As 2019 LNG netback price expectations increased over the same period, this meant that offers from southern suppliers were on average being priced below Victorian buyer alternative prices, and by April 2018 had converged with 2019 LNG netback prices at Wallumbilla.

As shown in chart 3.9, in the subsequent period between April and August 2018, as 2019 LNG netback price expectations have risen, there has been a commensurate increase in price offers from both producers and retailers/aggregators in the Southern States. By August 2018, offers from retailers/aggregators were on average around \$11/GJ and in line with expected netback prices, while offers from producers averaged around \$10.20/GJ.

The information provided to the ACCC by southern suppliers indicates that prices of offers have, on average, been consistent with expectations of 2019 LNG netback prices. However, as shown in chart 3.6, prices of individual offers can vary significantly around the averages shown in chart 3.9 above. For example, during mid-2018 when expected 2019 netback prices were around \$10/GJ, many offers from southern suppliers were above \$11/GJ. Further, during August 2018 when expected netback prices were around \$11/GJ, some offers from southern suppliers were as high as \$12.50/GJ.

However, while many offers by southern suppliers have been made above expected 2019 LNG netback prices during 2018, the information collected by the ACCC shows that southern suppliers have offered prices below expected netback prices. This is particularly the case in the latter months of the offer information available at the time of this report: in August 2018, when expected netback prices were around \$11/GJ, several offers were made (by both producers and retailers/aggregators) below this level, with some offers being made below \$10/GJ.

As noted in section 1.4, the supply-demand balance in the Southern States is expected to be in surplus in 2019 by around 28 PJ, which is consistent with the expectation that existed at the time of the July 2018 report. The trend in prices over the 18 months to August 2018—in particular in the latter months of this period where many offers were made below expected 2019 LNG netback prices—is consistent with a shift in market expectations about the likelihood of a gas supply shortfall, and the level of competition between suppliers, in the Southern States.

However, notwithstanding that many of the more recent offers from southern suppliers have been priced below expected 2019 LNG netback prices, the offers being made by producers in the Southern States—as is the case of offers from Queensland producers—are well in excess of Core Energy's estimated forward cost of production of the marginal source of supply in the east coast. Offers from southern producers were also significantly above the quantity-weighted average of the forward cost of production across all supply regions in the Southern States, which based on Core's estimated costs of production and 2P reserves, is \$3.76/GJ. The highest lifecycle cost of production of any supply region in the Southern States estimated by Core is \$8.25/GJ. However, this cost estimate is for the Kipper supply region in the Gippsland basin which, as discussed in section 2.10, is significantly above the cost of other new conventional gas developments due to the difficulties the GBJV has

experienced in developing this particular gas field. The next highest lifecycle cost of production in the Southern States estimated by Core is \$6.50/GJ for the Sole gas field in the Gippsland basin.

Therefore, prices offered by southern producers from January 2017 to August 2018 were significantly in excess of Core's estimated forward and lifecycle breakeven costs of production across supply regions in the Southern States. However, only a minority of these offers were accepted by gas buyers. As shown in table 3.3 below, the average of the gas commodity prices expected to be paid to southern producers under GSAs executed between January 2017 and August 2018 is \$9.37/GJ. Based on Core's production cost estimates, this indicates that the margins achieved by southern producers for gas supply in 2019 are likely to be substantial.

As noted in box 3.5 above, when there is sufficient supply and a diversity of suppliers in the Southern States, gas buyers are likely to be in a better bargaining position relative to suppliers than under tighter and less competitive market conditions. That is, when negotiating with a supplier, buyers would have the alternative of purchasing gas from another supplier in the Southern States rather than having to transport it from Queensland. In this environment, increased competition is likely to lead suppliers to offer prices closer to the 'seller alternative' price.

Therefore, with prices offered by suppliers in the Southern States having been generally in line with expected 2019 LNG netback prices at Wallumbilla over the middle months of 2018, improved confidence about sufficiency of supply and greater levels of competition among suppliers could have seen average prices fall further by over \$2/GJ to be closer to seller alternative levels. For offers made to some domestic gas buyers in recent months closer to the Victorian buyer alternative prices, the difference could have been up to \$4/GJ.

3.5.4. Recent changes in expectations of 2019 LNG netback prices

As shown in charts 3.8 and 3.9 above, with changing LNG market expectations around Asian LNG spot prices, the levels of LNG netback prices and buyer and seller alternative prices are also subject to change. The charts above show these price comparators up to the end of August 2018, in order to align with the most recent information the ACCC has obtained from suppliers for the purpose of this report.

However, as shown in chart 3.10 below, expectations of 2019 Asian LNG spot prices, and hence expected 2019 LNG netback prices at Wallumbilla, continued to exhibit volatility up to the end of November 2018.

Chart 3.10: Expected 2019 LNG netback prices at Wallumbilla (since July 2017)



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

Chart 3.10 shows that expected LNG netback prices at Wallumbilla for 2019 have changed significantly over 2017 and 2018. Expected 2019 netback prices trended upwards from around \$6.50/GJ in July 2017 to over \$12.50/GJ in September 2018. However, there was a significant drop over the subsequent two months, with expected 2019 netback prices falling to \$9.27/GJ as at 27 November 2018.

These changes in expectations of Asian LNG spot prices over a relatively short period show the potential for price volatility in the LNG market. It emphasises that sudden and unexpected changes in LNG supply and demand dynamics can have short-term impacts on price expectations.

However, it is important to note that, while recent LNG price expectations have mostly trended upwards over the past 18 months, this will not necessarily continue. ICE JKM futures prices over 2020, while based on fewer trades, are lower than prices quoted for 2019. As at 27 November 2018, the average JKM futures price for 2019 was US\$8.74/GJ, while for 2020 it was US\$7.97/GJ.

3.6. Recent experiences of C&I gas users

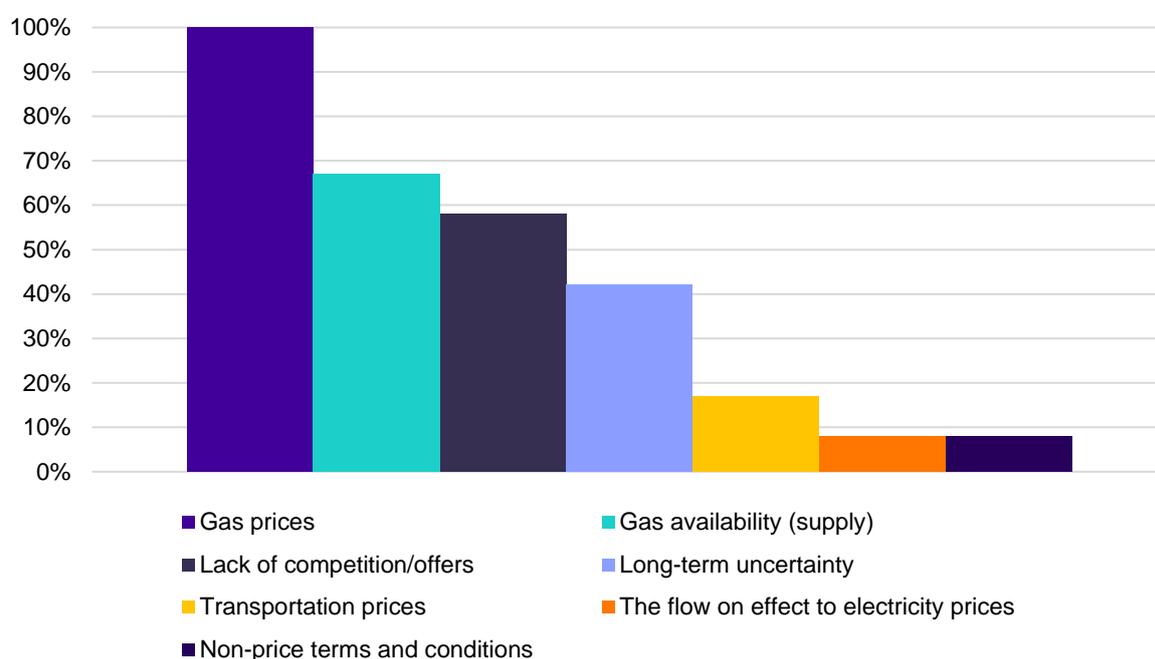
During September and October 2018, we surveyed a range of commercial and industrial (C&I) gas users to gain insight into their most recent experiences in the gas market since we last reported in July 2018¹²³. We asked these users to rank the key issues they were facing in the market. In Chart 3.11 we show the concerns that users ranked in their top three.

When considering current market conditions, all the C&I gas users we surveyed ranked gas prices as one of their top three most important concerns in relation to their gas supply.

¹²³ The ACCC consults with C&I gas users regularly through surveys and interviews. This information is based on survey responses from 12 C&I users and a number of meetings. The C&I users we surveyed represent all eastern states and range in gas consumption profile from comparatively small C&I gas users (<0.1PJ/a) to very large users (>5 PJ/a).

Availability of supply, lack of competition amongst gas suppliers and long-term uncertainty were also prominent concerns.

Chart 3.11: Top three concerns for C&I gas users



Note: Y-axis label is % of participants that ranked each concern in their top three.

In July 2018, we reported that only a handful of the C&I gas users that we consulted with had contracted their gas supply for 2019. By October, most of these users had contracted gas for 2019 and were focussing on securing supply for 2020 onwards.¹²⁴

Gas prices reported by C&I gas users trend higher in recent offers

There have been some high profile new agreements announced recently, such as the widely publicised deals between Santos and Brickworks,¹²⁵ and between Cooper Energy and O-I Australia.¹²⁶ While these reports are encouraging signs that C&I gas users have been able to secure supply, our most recent survey of C&I gas users suggests a more varied experience, with fewer active suppliers and prices trending higher than when we last reported.

C&I gas users seeking gas supply for 2019 since May 2018 reported higher priced offers compared to earlier this year, consistent with the trend observed in section 3.4 and chart 3.6 above (though not as high as peaks observed in 2017).¹²⁷ Information supplied by some users indicates that market prices further increased after the August 2018 cut-off for gas suppliers to provide compulsory information to the ACCC.

¹²⁴ This statement contrasts our reporting in section 3.4 that the vast majority of recent offers were not accepted. This discrepancy is likely to be because our information is based on user feedback received up to October 2018 while information we have on market prices is to August 2018. In addition, our sample of C&I users is representative only and does not cover all users in the market.

¹²⁵ Santos, 'Santos signs new long term domestic gas supply deal with Brickworks', media release, 12 Sep 2018.

¹²⁶ Cooper Energy, 'New Casino Henry gas contract with O-I Australia', ASX Announcement / Media Release, 10 October 2018.

¹²⁷ Noting that this statement applies only to prices offered and not prices agreed in GSA's over the same period. More data on prices agreed is in section 3.7.

While the C&I gas users we consulted had not received many firm offers for 2020 onwards, early indications suggest prices for longer-term supply are also increasing. Contracts also continue to shift towards more frequent, shorter-term contracts (1–3 years), which means as the remaining legacy long-term contracts conclude, users will be seeking new arrangements more frequently over the next few years.

Many C&I gas users were concerned that suppliers are increasingly only offering prices that are oil-linked (compared to fixed price or CPI linked prices). With less offers to choose from (discussed below), users indicate they may have to accept an oil-linked price, with the associated financial risk and added long-term uncertainty. As broader market prices are increasingly exposed to international prices, users are also concerned about the risk of higher future market offers due to unfavourable movements in oil and LNG prices, and the Australian dollar.

Users express concerns about a lack of offers for gas supply

C&I gas users also raised concerns about the lack of competition amongst gas suppliers and the limited number of offers for gas supply. Users observed that the lack of competition gave suppliers increased bargaining power in the prices and terms they offered.

“The lack of market competition is providing opportunities for those holding gas to inflate prices when international oil or LNG prices increase despite their gas books being unlikely tied that closely to current international price movements. We believe this is occurring due to the lack of market competition and lack of forward purchasing of gas by retailers.”

Large east coast gas user, September 2018

Compared to the improved situation we reported in July 2018, C&I gas users that have recently been active in the market for 2019 supply reported fewer suppliers making offers towards the end of 2018, as suppliers’ portfolios became fully contracted for the year ahead. As described by the following user:

“We have seen gas prices for 2019 supply in Victoria increase by close to \$2 since we first approached the market in early June. We have also seen the number of suppliers providing fixed price offers decrease from 5 in early June to only 2.”

Large east coast gas user, October 2018

In July, we reported that some C&I gas users had begun seeking supply for 2020 and beyond. At that time, users noted suppliers were constructively engaging in preliminary discussions for future supply, and several users hoped to finalise deals by the end of 2018.

As of October 2018, many users reported that they were still engaging in genuine discussions with a range of suppliers for supply from 2020, and several had also participated in producers’ Expression of Interest gas sales processes. However there was a lack of firm offers being made and several suppliers advised they had no gas to offer beyond 2020. While this is cause for some concern, the ACCC will continue to monitor and report on the situation and we expect that, consistent with more recent market practices, contracts for 2020 are likely to be signed during 2019.

Concerning producer behaviour

Just prior to this report being finalised, a number of C&I users contacted the ACCC greatly concerned with the behaviour of at least one producer. These manufacturers had each reached an in-principle agreement with a retailer for gas supply from 2020 and 2021. However the retailer had entered into these arrangements based upon a yet to be finalised gas supply agreement with a producer which was then withdrawn for re-offer in late 2018. One of the users had turned down other firm offers in the middle of 2018, when there were more active gas suppliers and offer prices were lower. The users are now very concerned that it will be difficult to secure supply at a similar price, if at all. This course of events does not reflect a well-functioning market.

Questions about longer-term viability of operations persist

In our July 2018 report, we detailed the significant concerns of C&I gas users about the business impacts of gas market conditions. In our most recent consultations, users maintained concerns about the longer term viability of their operations.

“As a major exporter from Port Botany of a range of food and industrial products, we are importing products into countries that are paying less than a third for gas prices. As a major manufacturing company, our process is energy intensive and we are not internationally competitive with high gas and electricity prices.”

Large east coast gas user, September 2018

“Prices are unsustainably high and unless resolved represent a challenge to the ongoing competitiveness and sustainability of [our Australian] operations.”

Large east coast gas user, October 2018

As outlined above users continue to see high gas prices as a threat to their ongoing viability and trade exposed users continue to emphasise the impact of high prices on their international competitiveness. Given the tight long-term supply outlook and current forward LNG prices, there are no clear signs that the situation will change significantly for these users.

3.7. Prices agreed under GSAs for 2019

This section analyses GSAs for supply in 2019 that were executed between 1 January 2017 and 30 August 2018.

Box 3.6 below sets out the ACCC’s approach to reporting on prices agreed under GSAs.

Box 3.6: Approach to reporting on prices agreed under GSAs

The information in this box should be read in conjunction with information in box 3.1. 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 with all counterparties, while for the purpose of the analysis of retailer/aggregator prices, we have only included GSAs executed with C&I gas users.
- In contrast to the analysis of offers and bids in section 3.4 above, we estimated prices under GSAs using assumptions relating to key variables (oil prices, foreign exchange rates and CPI) based on the latest market expectations for those variables for 2019 (to allow us to report on prices that are currently expected to be paid under GSAs in 2019).¹²⁸
- These market expectations have changed since we last reported on GSA prices in July 2018. Expectations for 2019 oil prices and exchange rates have decreased since July, while CPI results since July have been below expectations. The aggregate effect of the changes in our assumptions since July is a decrease in expected GSA prices for 2019.

Table 3.3 shows the averages of gas prices expected to be paid for supply in 2019 under GSAs entered into by producers. Table 3.4 shows the averages of gas prices expected to be paid for supply in 2019 under GSAs entered into by retailer/aggregators. The prices in these tables are not directly comparable to the prices previously reported in the July 2018 report due to changed pricing assumptions. Further, both producers and retailers/aggregators have entered into a larger number of new GSAs for 2019 than they had in the early months of this year. Due to the larger number of GSAs, we are reporting prices at a greater level of disaggregation than in our July 2018 report.¹²⁹

Table 3.3: Expected 2019 wholesale producer gas commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2017 and 30 August 2018)

Origin of producer supply	Average gas commodity price (\$/GJ)	Gas commodity price range (\$/GJ)
Producers (QLD)	8.36	7.63 – 8.52
Producers (VIC only) ¹³⁰	9.72	9.31 – 10.71
Producers (VIC and SA)	9.37	8.71 – 10.71

Source: ACCC analysis of information provided by suppliers.

Table 3.3 shows that in the period between 1 January 2017 and 30 August 2018, the average of prices in GSAs executed by producers in the Southern States is higher than the average of prices in GSAs executed by producers in Queensland. The observed price difference is similar to the price difference we reported in July.

¹²⁸ In all estimates of 2019 GSA prices in this report, the following assumptions were made, where relevant:

- Consistent with Commonwealth Treasury methodology, the AUD/USD exchange rate for 2019 is expected to vary around the current rate. The exchange rate assumption applied to GSAs in this report is 72.22 US cents to the Australian dollar. It is based on the monthly rate published by the RBA for September 2018.
- The expected Brent crude oil price for 2019 is equal to the average price of 2019-dated futures contracts quoted by CME Group on 14 November 2018.
- The CPI assumptions used to estimate GSA prices in this report are based on actual CPI where available and 2.5 per cent thereafter (source: ABS).

¹²⁹ Producer prices are reported with reference to the state in which the gas is produced. Where a producer may be supplying a buyer with gas from more than one state, it is assumed that the closest production source to the specified delivery point is the source of the gas.

¹³⁰ Specifies the average of prices under GSAs entered into by producers that only produce gas in Victoria.

The current price difference between Queensland and the Southern States is due to higher cost GSAs for gas supply from Victorian producers to retailer/aggregators. The Victorian producer GSAs are at higher prices, on average, than GSAs from producers in the other states. The range of agreed prices for gas supply from Victorian producers is also wider than the range of agreed prices from producers in Queensland or South Australia.

Table 3.4: Expected 2019 Retailer/Aggregator gas commodity prices for supply to C&I gas users (under GSAs executed between 1 January 2017 and 30 August 2018)¹³¹⁻¹³²

Destination of retail supply	Average gas commodity price (\$/GJ)	Gas commodity price range (\$/GJ)
Retailers/aggregators (VIC)	10.66	9.00 – 12.51
Retailers/aggregators (QLD)	11.76	9.85 – 12.23
Retailers/aggregators (NSW)	9.54	9.00 – 10.5

Source: ACCC analysis of offer and bid information provided by suppliers.

Table 3.4 shows that the averages of gas commodity prices in GSAs between retailers/aggregators and C&I gas users across the Southern States and Queensland are higher than the averages of gas commodity prices in GSAs entered into by producers.

The average of retailer/aggregator prices in Queensland is higher than averages of retailer/aggregator prices in other states and higher than average of producer prices in Queensland, because of the influence of high priced oil-linked GSAs. The number of retailer/aggregator GSAs for gas supply in Queensland is relatively small, so individual GSAs at high prices can significantly increase the average of prices.

Table 3.5 shows expected producer gas commodity prices for Victoria and South Australia (all buyers) and retailer/aggregator prices for Victoria and NSW (C&I gas users) for GSAs executed between 25 April 2018 and 30 August 2018 for gas supply in 2019. We have chosen not to include other state averages because there are only a small number of applicable GSAs.

Table 3.5: Expected gas commodity prices for supply by producers (to all buyers) and retailers/aggregators (to C&I gas users) in the East Coast Gas Market in 2019 (under GSAs executed between 25 April 2018 and 30 August 2018)¹³³⁻¹³⁴

Category of supplier	Average gas commodity price (\$/GJ)	Gas commodity price range (\$/GJ)
Producer (VIC and SA)	9.49	9.00 – 10.71
Retailers/aggregators (VIC)	9.62	9.00 – 11.95
Retailers/aggregators (NSW)	9.64	9.21 – 10.50

Source: ACCC analysis of offer and bid information provided by suppliers.

¹³¹ Pricing assumptions applied to GSAs in this section are the same as applied in section 3.4 above. Prices are for gas commodity charges only; actual prices paid by users may also include separate charges for transport and retail cost components.

¹³² In our July 2018 report we published a combined Victorian, South Australian and NSW expected average retailer/aggregator price for 2019, rather than the separate prices for states published in this table. The combined expected average retailer aggregator price for Victoria and South Australia and NSW is \$9.91 per GJ.

¹³³ Pricing assumptions applied to GSAs in this section are the same as applied in section 3.4 above. Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components.

Table 3.5 shows that the averages of prices for the most recently executed GSAs for these locations and supplier types are similar to each other with a range of only 15 cents between the smallest and largest average price. The averages for Southern state producers and retailer/aggregators in New South Wales are also similar to the average of prices of GSAs executed since 1 January 2017. The average of Victorian retailer/aggregator prices for the most recent GSAs is significantly lower than the average since 1 January 2017, but this is due to the influence of one large GSA included in the older GSAs, rather than a general reduction in prices. Overall, the comparison of recently executed GSAs with GSAs executed since 1 January 2017 indicates that conditions in the domestic east coast gas market have been relatively stable so far over the second half of 2018.

Table 3.6 shows the expected average prices of commodity gas supplied to gas powered generation in the East Coast Gas Market (under GSAs executed between 1 January 2017 and 30 August 2018 for a term of 12 months or more). This average is based on a small number of GSAs because most gas powered generation is not supplied with gas under specific GSAs. Gas powered generation is more commonly supplied from within the portfolios of related party retailers.

Table 3.6: Gas commodity prices expected to be paid in 2019 by gas powered generators in the East Coast Gas Market (under GSAs executed between 1 January 2017 and 30 August 2018)

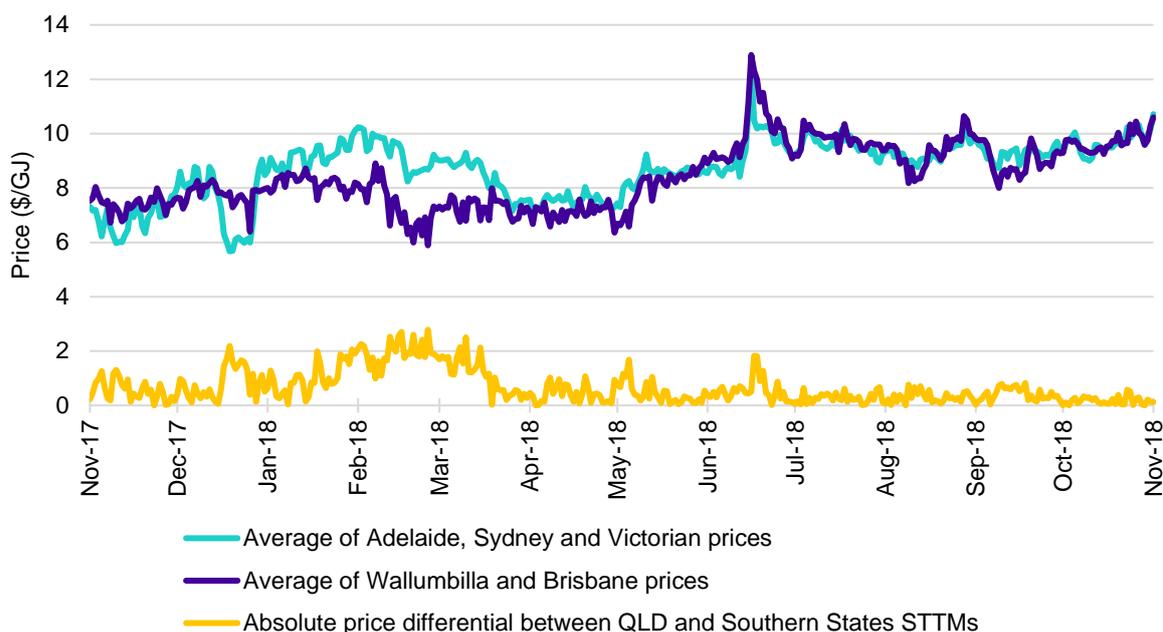
Production Source	Average gas commodity price (\$/GJ)	Gas commodity price range (\$/GJ)
Producers (SA, VIC)	9.26	8.80 – 10.45

The average of gas commodity prices expected to be paid by GPGs in 2019 under GSAs executed between 1 January 2017 and 30 August 2018 is \$9.26/GJ, which is higher than the average of \$9/GJ we reported in July 2018. The average of prices of gas to supply GPGs remains similar to the average of prices of wholesale gas supply from producers to other gas buyers in the market, albeit at the lower end of the range.

3.8. Prices paid in short-term trading markets

Chart 3.12 shows the daily prices paid for gas in the short-term trading markets (STTM) in the Southern States (the simple average of the Victorian DWGM, the Sydney STTM and the Adelaide STTM) and Queensland (the simple average of the Wallumbilla GSH and the Brisbane STTM) from early October 2017 to early October 2018. The chart also shows the absolute price difference between the markets in Queensland and the Southern States.

Chart 3.12: Daily prices paid in domestic short-term trading markets, October 2017 to October 2018



Source: AEMO

Chart 3.12 shows that since the last interim report in July 2018, prices paid in short-term trading markets in Queensland and the Southern States have fluctuated within \$8/GJ-\$10/GJ range. Moving slightly past \$10/GJ late in October 2018. This range is relatively narrow when compared to past periods of high volatility.

Prices paid in northern and southern markets have tracked each other closely; the absolute price differential between Queensland and the Southern States STTMs has remained below \$1/GJ since July 2018.

For the month of October, the simple average of the prices in short-term trading markets in the Southern States was \$9.53/GJ compared to \$9.50/GJ in Queensland.

Recent prices in domestic short-term trading markets in the Southern States are higher relative to the same period in the previous year. The simple average of prices in the Southern State STTMs was \$9.40/GJ for the third quarter of 2018 compared to \$8.61/GJ for the third quarter of 2017 (a 9.18 per cent increase).

In Queensland, the price changes have been greater than those in the Southern States. The simple average of prices in Queensland STTMs was \$9.42/GJ for the third quarter of 2018 compared to \$6.77/GJ for the third quarter of 2017 (a 39.14 per cent increase). Increased trading volumes associated with LNG plant tender testing may have depressed third quarter 2017 Queensland prices.

The quantity of gas traded in short-term trading markets in the Southern States has decreased, however the change in quantity is within the range of normal variation. In aggregate 92.5 PJ of gas was traded in Adelaide, Sydney and Victoria in the third quarter of 2018 as compared to the 94.5 PJ of gas that was traded in the third quarter of 2017.

In Queensland, there has been an increase in the quantity of gas traded on the Wallumbilla gas supply hub and a decrease in the quantity of gas traded on the Brisbane STTM. A total of 5.96 PJ of gas was traded in the third quarter of 2018 on the Wallumbilla gas supply hub

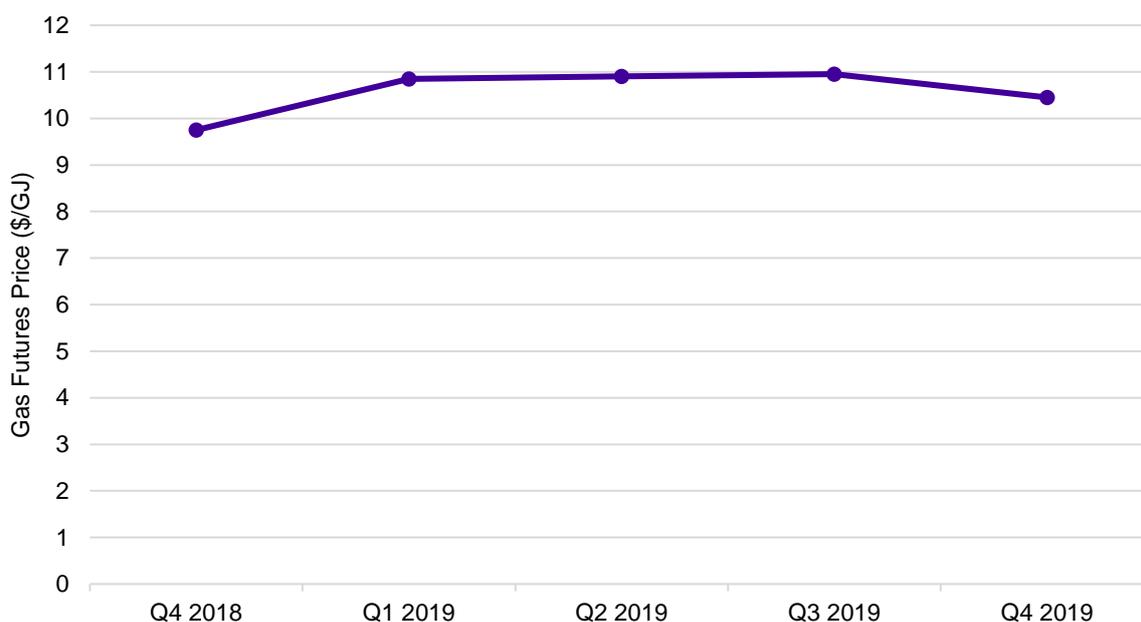
and 6.9 PJ was traded on the Brisbane STTM. In the third quarter of 2017, 3.56 PJ was traded on the Wallumbilla gas supply hub and 7.6 PJ was traded on the Brisbane STTM. The increase in the quantity of gas traded at the Wallumbilla gas supply hub is consistent with an ongoing increase in the liquidity of this exchange.

3.9. Gas futures trading in Victoria

There has been an increase in the level of trading of Victorian gas futures contracts in the past few months. In August 2018, 68 quarterly contracts were traded. In September 2018, 75 quarterly and 10 yearly contracts were traded. In October 2018, 133 quarterly and 25 yearly contracts were traded. Up to 14 November 2018, 155 quarterly and 25 yearly contracts have been traded. Prior to this, no quarterly or yearly contracts were traded in June or July 2018, while 10 quarterly contracts were traded in May 2018. In total, in the period between May 2018 to 14 November 2018, 441 quarterly contracts and 60 yearly contracts were traded amounting to approximately 4.57 PJ of gas. The amount of open interest in quarterly futures contracts has significantly increased since the ACCC last reported on the emergence of gas futures. This, in conjunction with bid-ask spreads narrowing, suggests that the Victorian gas futures market is becoming more liquid.

The futures prices shown in chart 3.13 indicate that market participants expect gas prices in the Victorian DWGM to remain relatively stable throughout 2019. Futures prices are slightly below \$10/GJ in the fourth quarter of 2018 and rise to just below \$11/GJ for the first three quarters of 2019, falling to \$10.45/GJ in the last quarter of 2019.

Chart 3.13: Victorian DWGM futures prices from Q4 2018 to Q4 2019



4. Transportation and storage

4.1. Key points

- Reforms to the gas transportation sector have continued since we last reported in July 2018. Since our last report, requirements for the publication of weighted average prices and financial information by non-scheme pipeline operators have started to take effect and will apply in full by 31 January 2019. The implementation of a capacity trading reform package is also underway and will commence on 1 March 2019.
- The outcome of the first arbitration under Part 23 of the National Gas Rules, together with the price reductions negotiated by some shippers, suggest that the introduction of Part 23 is a positive development for shippers but other factors (such as the ACCC Inquiry or the impending introduction of the capacity trading reforms) may also be influencing these outcomes.
 - The Tasmanian Gas Pipeline (TGP) was subject to the first arbitration under the new information disclosure and arbitration framework and has seen prices significantly decrease. The maximum price paid by shippers on that pipeline is now 56 per cent lower than it was in 2017, while the minimum price paid by shippers is 4 per cent lower.
 - Some shippers have also been able to negotiate price reductions in new gas transportation agreements and variations and have accessed increased flexibility, particularly in relation to interruptible and/or ancillary services (such as park and loan and backhaul services).
- However, current transportation prices are still too high. This is in part due to the time it is taking for these reforms to take effect; for example, shippers continue to pay prices in contracts negotiated prior to the commencement of the reforms. We have also continued to find that the standing prices published by non-scheme pipeline operators under Part 23 are usually higher than the prices agreed in new contracts. Shippers should be able to negotiate a better deal with pipeline operators.
- The ACCC therefore remains concerned that the information published under Part 23 may not be posing enough of a constraint on the exercise of market power by pipeline operators. It may indicate a need to further refine the information disclosure requirements. We will continue to monitor the effectiveness of the reforms over the remainder of our inquiry.
- With pipeline capacity trading reforms yet to take effect, key pipelines remain contractually congested. However, some pipeline operators have taken steps to try to alleviate the contractual constraints on their pipelines and facilitate the movement of gas into the Southern States. We expect increased trading of capacity to occur following the commencement of the capacity trading reform package on 1 March 2019.
- There has been some investment in new pipelines to bring new sources of supply south, including Jemena's Northern Gas Pipeline (NGP) to link the Northern Territory to the east coast. That said, there has been limited investment to expand pipeline capacity on the key transmission pipelines linking Queensland to the Southern States. This appears to be largely due to existing and prospective shippers on those pipelines not entering into long-term GTAs to underwrite the required investment.
 - Between 1 August 2018 and 30 August 2018, there were 26 new GTAs and variations resulting in new prices for firm forward haul services. Of these, 17 were for a term of one year or less, 9 were for a term of between one year and five years and none were for a term of five years or more.

- Access to storage is also likely to become increasingly important in managing pipeline congestion and ensuring gas from Queensland is available to supply gas consumers in Southern States. The ACCC is reporting prices for gas storage at Dandenong LNG and Iona underground storage for the first time. We have also, together with the Gas Market Reform Group (GMRG), recommended to the Australian Government that further reforms be implemented that provide for the ongoing reporting of prices for storage (and compression) services.

4.2. Most gas transportation and storage prices are unlikely to change significantly until current contracts roll over

4.2.1. Gas transportation prices, with some exceptions, continue to increase with inflation

The ACCC's 2015 inquiry found evidence of a large number of existing pipelines engaging in monopoly pricing, which resulted in higher delivered gas prices for users and associated adverse effects on economic efficiency.¹³⁵ In our December 2017 report, we examined the prices paid for firm forward haul services on major transmission pipelines as at July 2017. We found that prices had largely increased in line with inflation since the 2015 inquiry.¹³⁶

We have again examined the prices paid by shippers for firm forward haul services on major pipelines as at July 2018. We have analysed the invoices issued by pipeline operators under gas transportation agreements (GTAs) entered into for a term of one month or longer. The map at figure 4.1 shows the minimum and maximum of the prices paid by shippers for these services in July 2018 and the changes in these minima and maxima that have occurred since July 2017.

¹³⁵ ACCC, *Inquiry into the east coast gas market*, April 2016, p. 92.

¹³⁶ ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2017, p. 67.

Over the 12 month period, most prices have increased in line with inflation. This is not surprising given that only 12 per cent of the GTAs included in the July 2018 invoices reflect prices from contracts entered into after July 2017 and CPI escalation is standard practice in most GTAs.

As Chart 4.1 shows, the most significant price change has occurred on the TGP, where the maximum price paid has decreased by 56 per cent following the entry into a new GTA by the shipper who was previously paying the most for access. The minimum price on this pipeline has decreased by 4 per cent following an arbitration under Part 23 of the National Gas Rules (further detail is set out below in box 4.1).

It is important to note that movements in the prices of firm services within the maxima and minima are not captured in figure 4.1. Chart 4.1 below provides a snapshot of the changes in invoiced prices for firm forward haul services from July 2017 to July 2018.

Box 4.1: Arbitration in relation to the Tasmanian Gas Pipeline

Since the introduction of Part 23 of the National Gas Rules there has been one arbitration between TGP and AETV Pty Ltd (a subsidiary of Hydro Tasmania).

The access dispute was referred to the arbitrator by the AER on 29 November 2017 and was in relation to the following services:

1. Firm forward haul service for the Tamar Valley Power Station (TVPS) and major industrial users
2. As available forward haul service
3. High priority storage service (HPSS) and Victorian Transmission System interconnect service (note that the request for this service was withdrawn during the course of the arbitration).

A final access determination was made on 12 April 2018. Following the arbitration, TGP and AETV entered a contract in accordance with the final access determination.

While the final determination is confidential, TGP has noted in its User Access Guide that the standing prices for the pipeline are based on the arbitrated outcome.¹³⁷

The TGP's standing prices for firm forward haul services are as follows:

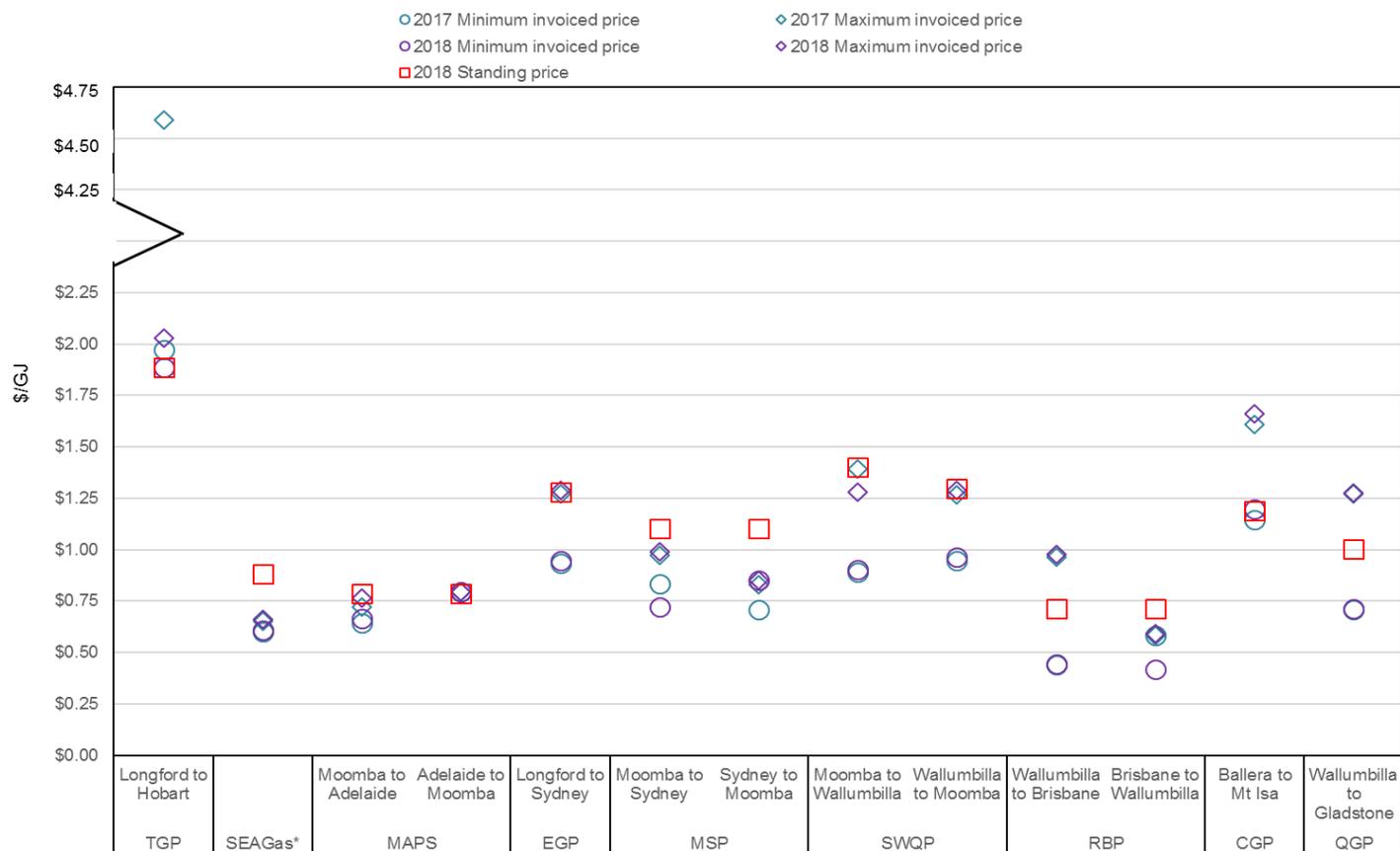
- Zone 1 (Comalso, Ecka): \$0.8926/GJ
- Zone 2 (Bridgewater (Hobart), Burnie, Carrick/Hadspen, Longford Tasmania, Port Latta, Spreyton, Ulverstone, Westbury, Wynyard): \$1.8856/GJ

As noted in our December 2017 report, the prices previously paid by shippers for this service ranged from \$1.97/GJ to \$4.59/GJ in July 2017.

The prices currently paid for firm forward haul services between Longford and Hobart range from \$1.89/GJ to \$2.03/GJ. This range reflects that one shipper entered into a GTA while the arbitration was on foot. Accordingly, this shipper was able to negotiate a price that was lower than the previous maximum price paid by shippers on the TGP but higher than the arbitrated price that forms the basis of the standing prices.

¹³⁷ Tasmanian Gas Pipeline, *Part 23 User Access Guide*, 18 May 2018, p. 12.

Chart 4.1: Changes in invoiced prices from July 2017 to July 2018 and the standing prices for firm forward haul services



Source: ACCC analysis of information provided by pipeline operators to the ACCC and published on their websites.

Notes: The term 'standing prices' is used to jointly refer to the standing prices that pipelines subject to Part 23 of the National Gas Rules are required to publish, the prices that pipelines subject to light regulation are required to publish for light regulation services and the reference tariffs that pipelines subject to full regulation are required to publish.

The prices published in this chart do not account for any differences in terms and conditions of individual GTAs from the terms and conditions set out in the published standing prices.

The invoiced and standing prices for a particular pipeline are not directly comparable to the invoiced and standing prices of another pipeline due to material differences in their characteristics (including length, size, construction cost, age and the extent of recovery of invested capital).

* The standing price for SEAGas is only for firm forward haul services on the Port Campbell to Adelaide pipeline and does not include receipt and delivery point charges. The invoiced prices, on the other hand, include receipt and delivery point charges and charges for use of the Port Campbell to Iona pipeline.

Chart 4.1 also includes the standing prices¹³⁸ for firm forward haul services. We noted in the April 2018 report that the standing prices published by pipeline operators were usually higher than the prices actually paid by shippers and that prospective shippers could likely negotiate a better deal than standing prices.¹³⁹ As can be seen in chart 4.1, this continues to be the case on the majority of pipelines. The most notable exceptions to this are:

- The TGP where the standing price is based on the outcome of an arbitration under Part 23 of the National Gas Rules that was completed in April 2018 (see box 4.1 for further information on the arbitration).¹⁴⁰ The standing price is lower than both the minimum and maximum prices that were payable by shippers as at July 2017.
- The Carpentaria Gas Pipeline (CGP) where the standing price was reduced by APA from \$1.62/GJ in January 2018 to \$1.19/GJ in July 2018. This standing price, which is in line with the minimum price paid by shippers in July 2018, is up to 40 per cent lower than the price that some shippers were required to pay under older gas transportation agreements in July 2018.¹⁴¹
- The Roma to Brisbane Pipeline (RBP) where the standing price was set by the AER in 2016. This standing price falls between the minimum and maximum prices that were payable by shippers as at July 2018.

Based on our review of the new gas transportation agreements and variations that have been entered into over the twelve month period, it would appear that a number of shippers have negotiated:

- lower prices for firm transportation (within the range set out in figure 4.1 above), interruptible transportation and other ancillary (i.e. park and loan and backhaul) services; and
- greater service flexibility (i.e. access to additional receipt and delivery points or amended terms).

Whether these developments reflect the effect of the new information disclosure and arbitration framework under Part 23 or other factors (such as the ACCC Inquiry or the impending introduction of the capacity trading reforms) is difficult to discern. The story has nevertheless been largely positive for those shippers that have entered into new gas transportation agreements or variations since August 2017, when Part 23 commenced.

As noted in our April 2018 report, the prevalence of standing prices that are higher than the prices actually paid by shippers raises potential concerns about whether the standing prices published by non-scheme pipeline operators are achieving the objectives of the disclosure obligations under Part 23. These objectives are to reduce the information asymmetries faced by shippers in negotiations and to enable them to negotiate more effectively. Together with the arbitration mechanism available under Part 23, the information disclosure regime is intended to address the monopoly pricing we identified in our 2015 inquiry into the east coast gas market.

The ACCC intends to continue to review the standing prices of non-scheme pipelines, including the methodologies employed by pipeline operators to determine these prices. This review will consider the standing prices alongside the weighted average price information

¹³⁸ The term 'standing prices' is used to jointly refer to the standing prices that pipelines subject to Part 23 of the National Gas Rules are required to publish, the prices that pipelines subject to light regulation are required to publish for light regulation services and the reference tariffs that pipelines subject to full regulation are required to publish.

¹³⁹ ACCC, *Gas Inquiry 2017-2020 Interim Report*, April 2018, pp. 48-49.

¹⁴⁰ Tasmanian Gas Pipeline, *Part 23 User Access Guide*, 18 May 2018, p. 12, available at: <https://www.tasmanianguaspipeline.com.au/client-assets/Part%2023/20180531%20TGP%20User%20Access%20Guide.pdf>.

¹⁴¹ See APA, *Current tariffs and terms*, APA's website: <https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/> accessed on 12 February 2018 and 29 October 2018.

and financial information published by some pipeline operators in October 2018 and due to be published by other pipeline operators by 31 January 2019.

4.2.2. Storage prices

Gas storage in the East Coast Gas Market is currently used by retailers, electricity generators, and large commercial and industrial customers to meet seasonal peak demand, manage market risks, respond to supply outages and maintain system security. Gas can be stored in underground storage facilities, pipelines and in LNG storage facilities. Each of these three types of storage facilities offer different types of services.

Underground storage facilities can be used to store relatively large volumes of gas for long periods of time and tend to be used by retailers in South Eastern Australia to manage seasonal demands. These facilities use depleted fields and the geology of the particular fields largely determines the capacity of the facility. LNG storage facilities, on the other hand, are used to store relatively small volumes of gas as LNG and tend to be used by retailers in South Eastern Australia to maintain system security and address short-term peaks in demand. Gas pipelines can also be used to store relatively small volumes of gas for short periods of time through park and loan services and tend to be used in South Eastern Australia to manage short-term peaks in demand.

As figure 4.1 highlights, there are a number of dedicated storage facilities in the East Coast Gas Market. There are, however, currently only two dedicated storage facilities that are providing storage services to third parties. Lochard Energy's Iona underground gas storage facility has significantly greater storage capacity (26,000 TJ capacity) compared to APA's Dandenong LNG storage facility (680 TJ capacity).

As noted in our December 2017 report, storage will be increasingly important to manage peak demand periods and ensure gas is available where it is needed. As outlined in chapter 1, based on current reserves and resources data, the East Coast Gas Market is likely to be heavily reliant on gas sources in Queensland in the future. Currently there is no publicly available information on the standing prices of the Iona or Dandenong storage facilities or on the actual prices paid by users of these facilities. This information asymmetry may adversely affect the efficient operation of the market and the efficient allocation of storage services by impeding the bargaining process and the efficient use of these services. Accordingly, we are reporting on storage prices for the first time during this inquiry.

The map at figure 4.1 reports the invoiced prices for storage at the Iona underground gas storage facility and the Dandenong LNG storage facility. The reported prices include a fixed and a variable charge. The fixed charge is a charge for the storage capacity and is measured on a price per GJ of storage capacity per day basis. The variable charge, on the other hand, which is measured on a dollar per GJ basis, reflects the liquefaction cost at the Dandenong LNG facility and the storage injection and withdrawal charges at the Iona underground storage facility.

The invoiced price range for the Iona underground storage facility includes a fixed charge of \$0.013–\$0.021/GJ of storage capacity/day, with variable charges of: \$0.08/GJ for injection into storage and \$0.01/GJ for withdrawal from storage via the SEA Gas Pipeline; and \$0.04/GJ for injection into storage and \$0.08/GJ for withdrawal from storage via the South West Pipeline. The invoiced price range for the Dandenong LNG storage facility is a fixed charged of \$0.066–\$0.087/GJ of storage capacity/day, with a variable charge of \$1.24 – \$1.34/GJ. Neither APA nor Lochard Energy publish standing prices for their storage facilities on their websites.

As can be seen in figure 4.1, the price for storage at the Dandenong LNG storage facility is significantly higher than at the Iona underground gas storage facility. This reflects the

different costs associated with the uses of the two facilities. The Dandenong LNG storage facility, for example, is used to store small amounts of gas to be injected quickly 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 the peak demand.

The ACCC considers that this pricing information will improve market transparency and promote more efficient use of, and investment in, storage infrastructure and services. While we will report on these prices periodically over the rest of this Gas Inquiry, we have also recommended, with the GMRG, that further reforms are implemented to provide for ongoing reporting of information on storage services.

4.3. Most new gas transportation agreements and price variations are for one year or less

As noted in our April 2018 report, a new regulatory framework for ‘non-scheme’ pipelines was implemented in August 2017.¹⁴² Questions have subsequently been raised about the number of GTAs that have been entered into under the new regulatory framework and on other full and light regulation pipelines. The Australian Pipelines & Gas Association, in February 2018, stated that more than 25 contracts had been negotiated since the new framework commenced, suggesting that the number of new contracts indicate that the market is working.¹⁴³

We have analysed the new GTAs and variations to GTAs that have been entered into since the commencement of this new framework across the following pipelines:

- APA owned pipelines: Moomba to Sydney Pipeline (MSP), South West Queensland Pipeline (SWQP), Amadeus Gas Pipeline, RBP and CGP
- Epic Energy owned pipelines: Moomba to Adelaide Pipeline System (MAPS) and South East Pipeline System
- Jemena owned pipelines: Eastern Gas Pipeline, Queensland Gas Pipeline and NGP
- SEA Gas owned pipelines: Port Campbell to Adelaide Pipeline and Port Campbell to Iona Pipeline
- Palisade owned pipeline: the TGP.

We have found that over the period 1 August 2017 to 30 August 2018, 22 new GTAs were entered into, while 81 variations to existing GTAs were executed. Of those 81 variations, only 24 resulted in new prices being determined for existing services or for new services.

The remaining 57 variations involved changes to other aspects of the GTA, such as receipt and delivery points, contract volumes and the term of the contract. While these variations did not involve changes in price, many of these variations provide the shipper with increased flexibility, for example in relation to the term or time of year that a service is available, which may have previously been unavailable. Variations that provide increased flexibility are often highly valued by shippers as it assists them to manage their portfolio in a more efficient manner.

It is important to note that there are existing long term contracts that are not captured in our analysis. Also, some shippers have multiple contracts and may be supplementing their existing GTAs with additional services, rather than entering into new contracts.

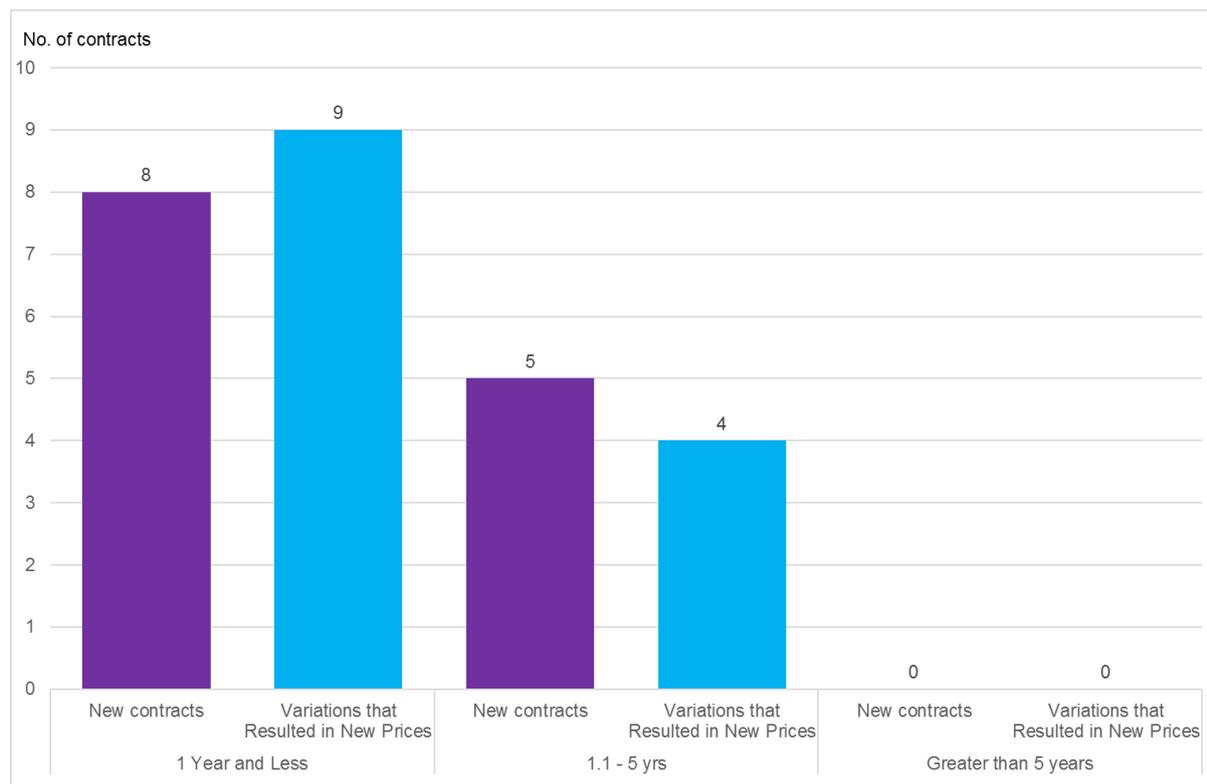
¹⁴² ‘Non-scheme’ pipelines are pipelines that are subject to neither full regulation nor light regulation under the National Gas Law and National Gas Rules.

¹⁴³ Australian Pipelines & Gas Association, ‘Pipelines delivering for gas customers’, media release, 27 February 2018.

Of the 46 new GTAs and variations resulting in new prices, 26 related to the provision of firm forward haul services while the remainder related to other transportation and ancillary services, such as interruptible transportation services, park and loan services, redirection services and capacity trading services.

As can be seen in chart 4.2 below, the majority (17) of the 26 new GTAs and variations resulting in new prices relating to firm forward haul services were for contract terms of one year or less. None of the new contracts or variations resulting in new prices for firm forward haul services were for a term of five years or more.

Chart 4.2: New Gas Transportation Agreements and Price Variations for firm forward haul services by term length



While new pipelines are still being underpinned by relatively long-term foundation contracts, we have observed that there is a trend toward shorter-term contracts on existing pipelines. Further we have observed that foundation contracts are rarely being renewed for terms greater than five years. This may reflect that shippers only have short-term contracts for gas supply, and consequently are contracting for transportation services for the same term. It is also consistent with feedback users have provided on the effect of uncertainties in the market relating to gas supply/demand dynamics, domestic gas prices, the level of domestic demand, and potential import terminals is having on contract terms. This shorter term approach to contracting may not change until the demand-supply outlook and future gas prices become clearer. It is possible that the current preference for short term contracts is also influencing investment decisions in capacity and compression expansion, discussed below in section 4.5.1.

The shippers that have entered into the new GTAs and variations largely fall into two categories: parties with GPG interests (some of whom are also retailers), and LNG exporters who are subject to the Heads of Agreement.

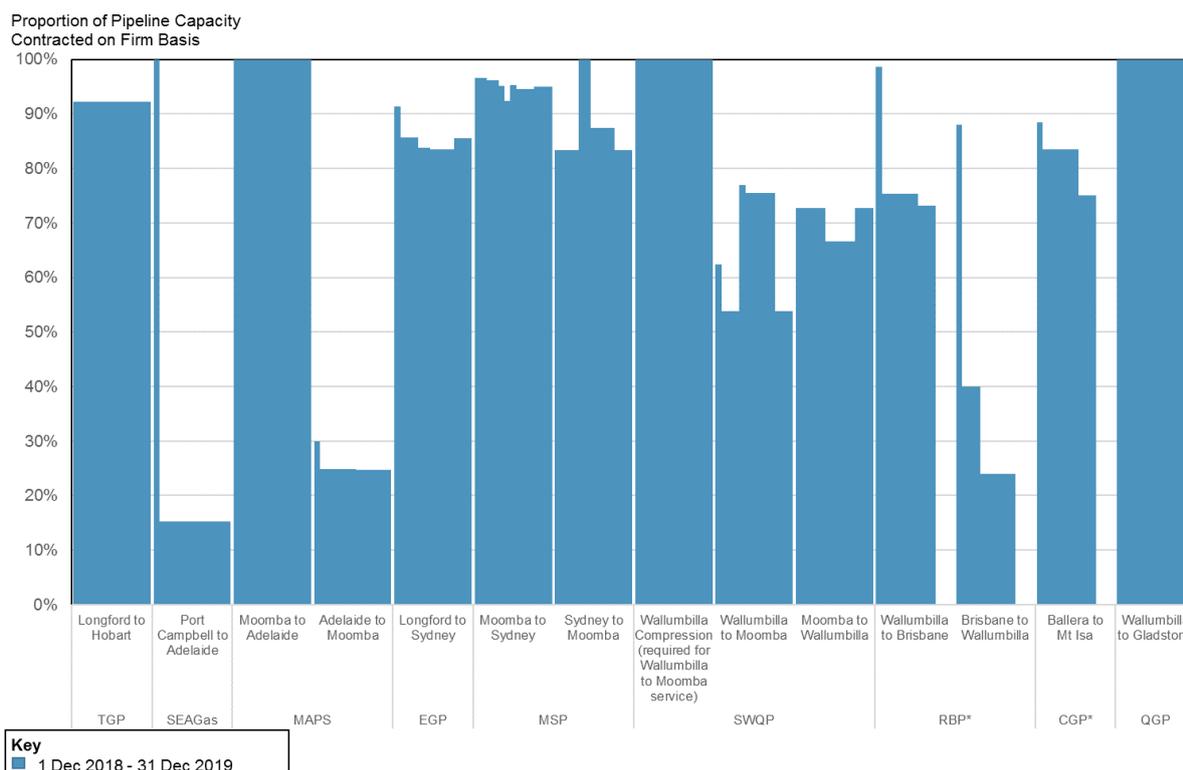
While shippers are contracting on a shorter term basis, they likely have different reasons for doing so. In relation to GPG, there is ongoing uncertainty regarding the role gas will play in the National Electricity Market. For the LNG exporters there is likely some uncertainty about how long they will be required to supply gas into the domestic market as well as uncertainty on the part of gas users over future prices and whether they should commit to longer-term contracts.

4.4. Key pipelines remain contractually congested, but some pipeline operators are taking steps to alleviate contractual constraints

As noted in our December 2017 report, gas transportation in the East Coast Gas Market (excluding the Victorian Declared Wholesale Gas Market) is currently dominated by bilateral agreements between service providers and shippers. The firm forward haul service is generally the most common service sought by customers as it has the highest priority of any transportation service. Where pipelines are contractually congested potential shippers seeking firm transportation services on that pipeline would need to seek alternative options.

Chart 4.3 below sets out the contracted capacity outlook for the major transmission pipelines in the East Coast Gas Market between 1 December 2018 and 31 December 2019. The SWQP along with the MSP and MAPS are the key transport routes to move gas from Queensland to the Southern States.

Chart 4.3: Contracted Pipeline Capacity (1 Dec 2018 – 31 Dec 2019)



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 6 November 2018).

For other pipelines (i.e. the Roma to Brisbane 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 6 November 2018).

* The uncontracted capacity outlook for these pipelines was only available until 30 September 2018.

As chart 4.3 shows, the Wallumbilla compression facility, which is required to transport gas on the SWQP between Wallumbilla and Moomba, is fully contracted over the next 12 months. The MSP is also close to fully contracted between Moomba and Sydney over this period, while the MAPS is fully contracted between Moomba and Adelaide. Bringing any additional gas from Queensland to the Southern States over the next 12 months could therefore be quite challenging, unless market participants are prepared to:

- rely on as available or interruptible services, which are lower in priority and typically more expensive than firm services
- 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.

The ACCC is aware that some pipeline operators have taken steps to try to alleviate the contractual constraints on their pipelines and facilitate the movement of gas into the Southern States during this period. One pipeline operator of a constrained pipeline worked with an existing long term shipper to de-contract capacity (that it was unable to utilise) and contract that capacity to another shipper. Another pipeline operator has managed the utilisation of their assets more efficiently.

In relation to secondary capacity trading, it would appear from publicly available information and information provided by retailers that limited trade has occurred on the key transportation routes between Queensland and the Southern States. This is expected to change in 2019 when the capacity trading reforms are implemented. These reforms, which were recommended by the AEMC, provide for the development of a capacity trading platform and a day-ahead auction of contracted but un-nominated capacity and a range of other reforms to facilitate the trade of capacity. Together, these reforms are expected to improve the efficiency with which capacity is allocated and used by:¹⁴⁴

- using market-based processes to allocate capacity to those that value it most
- improving the incentive shippers have to trade capacity and posing a constraint on the ability of pipeline operators to sell secondary capacity at prices in excess of what would be expected in a workably competitive market
- reducing search and transaction costs and aiding the price discovery process.

4.5. Further investment in pipelines and storage facilities is likely to be required over the medium to longer-term

Over the last year, two new pipelines have either been commissioned or are soon to be commissioned (the Reedy Creek to Wallumbilla Pipeline and the NGP) and the CGP has been converted into a bi-directional pipeline. These investments will enable more gas to flow into the domestic market from the Northern Territory and the Surat basin in Queensland.

Looking forward, it would appear from information provided by pipeline and storage facility operators that additional investments in capacity are expected to occur on a number of other pipelines and storage facilities.

An overview of these proposed investments is provided below.

¹⁴⁴ Gas Market Reform Group, *Consultation Paper: Capacity Trading Reform Package: Draft legal and regulatory framework*, 19 March 2018, p. 1.

A number of these proposed investments are designed to facilitate the movement of gas from Queensland to supply the southern domestic market. As noted in Section 2.3, the bulk of reserves and resources in the east coast are held by LNG producers in Queensland.

4.5.1. Pipeline investments

Current pipeline investments are focused on bringing new sources of supply to market rather than overcoming the contractual congestion on existing pipelines or compression facilities. These new investments are being underwritten by gas suppliers (producers and retailers).

As noted in our July 2018 report, Jemena will build, own and operate a 40TJ/day gas processing facility and pipeline to transport gas from Senex Energy's Project Atlas in the Surat Basin to the Wallumbilla Hub via the Darling Downs Pipeline.¹⁴⁵ This development is expected to enable gas to be delivered to the East Coast Gas Market by late 2019.

Jemena has also fast-tracked its plans to develop the Galilee Basin and construct a new pipeline to link with the East Coast Gas Market. The pipeline will deliver gas from Galilee Energy's Glenaras Gas Project and is expected to enable gas to be delivered to the East Coast Gas Market in 2022.¹⁴⁶

As noted in Section 1.6 of this report, Jemena has also indicated that it will look to extend and expand the NGP.

In addition to these projects, APA has, as noted in our July 2018 report, entered into a development agreement and a 20-year GTA to construct a 55km, bi-directional pipeline from AGL's proposed Crib Point LNG import facility to APA's Victorian Transmission System near Pakenham.¹⁴⁷ AGL's Crib Point Project is one of four import terminal projects currently being considered to increase supply to the East Coast Gas Market. A summary of the four projects is provided in table 1.1.

The ACCC has seen information that suggests that one pipeline operator of a contractually constrained pipeline is considering expanding the capacity of this pipeline, subject to market needs. Another pipeline operator has considered expanding the capacity of their contractually congested pipeline but has not received the required contractual commitments from shippers to underwrite the capital investment required, resulting in a failure of the expansion to proceed. As noted in section 4.4 above, some pipeline operators are taking other measures to provide access to the existing capacity (for example by buying back unutilised firm capacity). As the East Coast Gas Market becomes more reliant on gas from Queensland, transportation capacity from Queensland to the Southern States will become increasingly important.

4.5.2. Storage investments

As noted in our December 2017 report, Lochard Energy is increasing the withdrawal capacity at its Iona underground storage facility.¹⁴⁸ Currently Lochard Energy intends to increase the withdrawal capacity from 440 TJ/day in mid-2018 to 570 TJ/day by January 2023.

¹⁴⁵ Senex Energy, *Senex and Jemena fast-track Project Atlas gas to domestic market*, 18 June 2018, <https://www.senexenergy.com.au/senex-and-jemena-partner-to-fast-track-project-atlas-gas-to-domestic-market/>.

See also, Jemena, *Jemena and Senex partner to fast-track new gas supply to market*, media release, 18 June 2018.

¹⁴⁶ Jemena, *Jemena fast-tracks plans to connect Galilee Basin to the east-coast gas market*, October 2017, <https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin>.

¹⁴⁷ APA Group, *APA to develop Crib point Pakenham pipeline for AGL's LNG import facility*, media release, 12 June 2018. See also, *AGL Crib Point Project*, <https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project>.

¹⁴⁸ ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2017, p. 73.

As noted in Section 2.3, further investments in storage capacity is likely to be required over the medium to longer-term to enable storage of gas from Queensland.

4.6. Future work

With a review of the new information disclosure and arbitration framework and pipeline regulation more generally to be conducted in 2019,¹⁴⁹ the ACCC intends in early 2019 to conduct a closer review of:

- the weighted average prices, financial statements, recovered capital values and other information published by pipelines that are subject to the information disclosure and arbitration framework under Part 23; and
- the timeliness and outcomes of negotiations on pipelines, including the new GTAs and variations to GTAs as well as the key components of these agreements/variations (such as price, term and other key terms and conditions).

The ACCC will recommend any necessary changes to Part 23 that arise from this review. In 2019, the ACCC will also monitor the effectiveness of the capacity trading reform package to determine whether it is working as intended, or if further reforms to facilitate capacity trading on key transmission pipelines in the East Coast Gas Market may be required.

¹⁴⁹ COAG Energy Council, *Gas Market Reform*, Bulletin Three, August 2018.

5. Retailer pricing

5.1. Key points

- The ACCC has conducted a preliminary review of the costs incurred (including the costs of procuring gas, transportation and storage) and the margins received by the three largest gas retailers in the east coast.
- For the four year period from 2014 to 2017, average retailer margins ranged from \$1.60/GJ to \$2.29/GJ and were the third largest cost component of delivered gas prices. While these margins may appear material, the ACCC emphasises that these are highly aggregated preliminary results, which require further examination before final conclusions can be made.
- Separate analysis indicates that the costs and margins are different across the retailers, and vary for particular customer types and locations. Given these complexities, the ACCC will report on its findings in two stages.
- In this report, we have set out our preliminary review, which focuses on the costs and margins of the three retailers combined, in supplying gas to customers across the entire East Coast Gas Market. We have set out 'cost stacks' which show, at an aggregate level, how the retailers' costs and margins have impacted the delivered price of gas paid by their customers.
- The second stage of the review will involve a more detailed examination of these matters at a jurisdictional level and by customer type and will be published in our interim reports in 2019.

5.2. Introduction

Retailers generally purchase gas from producers, package it with transmission, distribution and other ancillary services and sell the gas on a delivered basis to a range of different customer types, including residential, small-medium enterprises, C&I, GPGs and other wholesale customers.

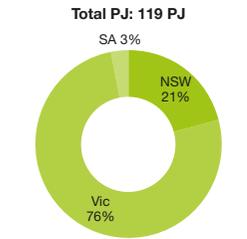
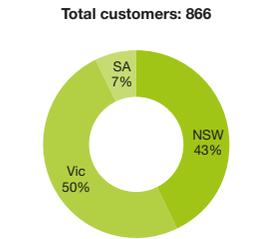
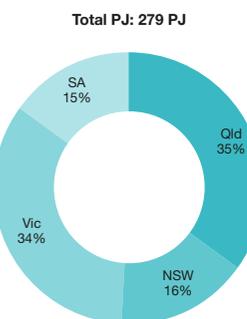
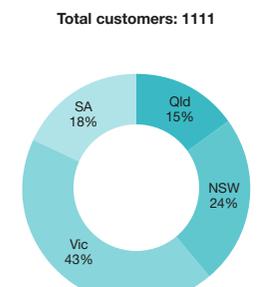
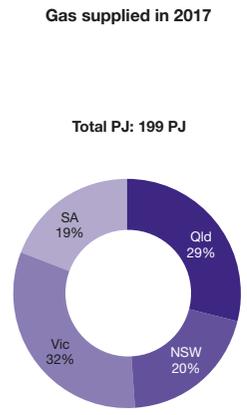
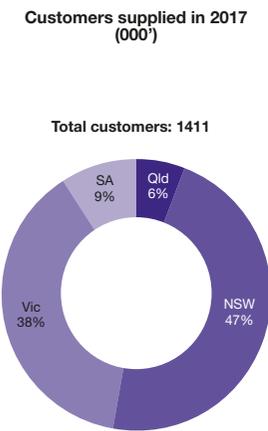
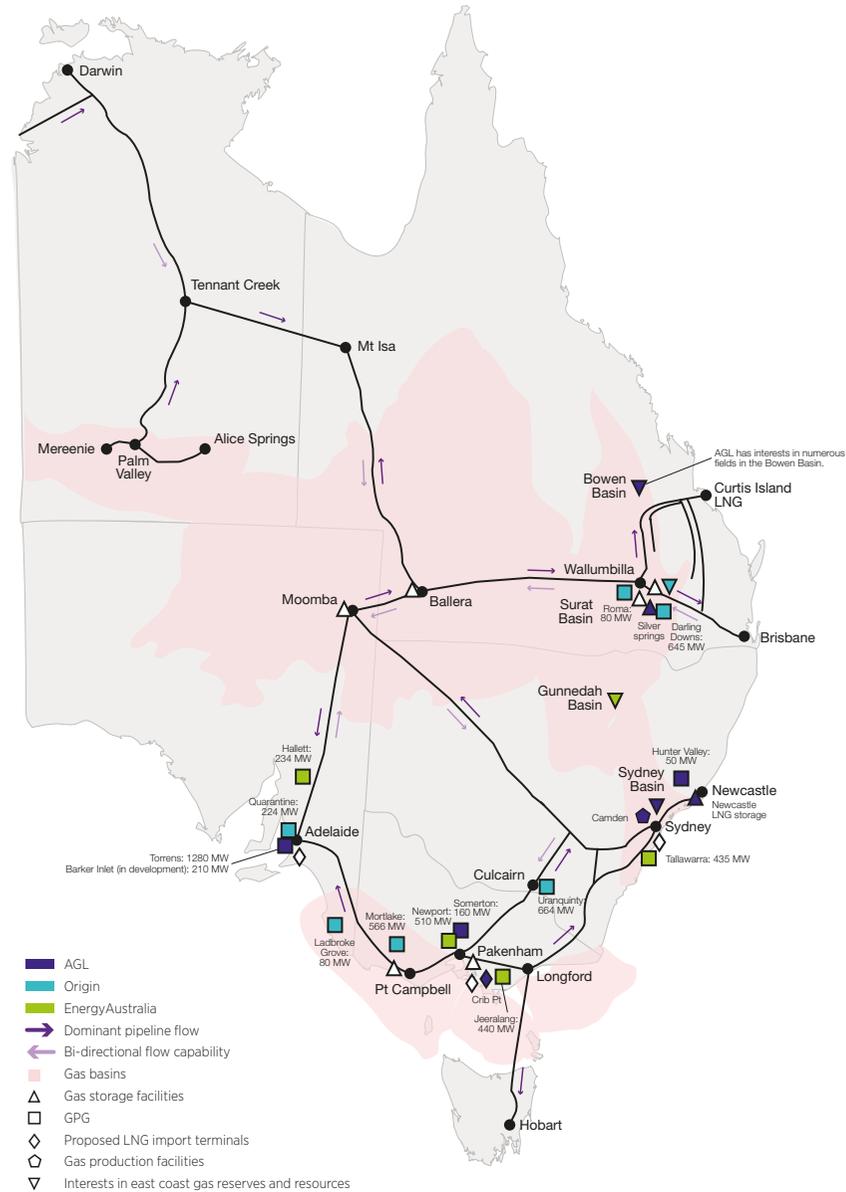
The three largest retailers in the East Coast Gas Market are AGL, EnergyAustralia, and Origin. Together these three retailers supply a large portion of C&I users and supply 80 per cent of small gas customers in southern and eastern Australia.¹⁵⁰

In order to understand the relative size and comparability of each of the three retailers, it is important to have regard to their range of interests. For example, the retailers have various interests in upstream gas reserves, production and storage that complement their interests in GPG and energy retailing, although some have scaled back these interests in the past two to three years.¹⁵¹ Further detail on the interests these retailers have in the East Coast Gas Market can be found in figure 5.1 and box 5.1 below.

¹⁵⁰ AER, *State of the Energy Market*, May 2017, p. 16.

¹⁵¹ AGL in February 2016 announced it planned to exit gas exploration and production, and would sell most of its gas production assets. It entered contracts with other suppliers to secure gas for its residential and small business customers. This announcement followed a decision by EnergyAustralia in October 2015 to sell its Iona gas storage plant in Victoria. Similarly, Origin in December 2016 announced it would divest its conventional upstream gas interests in the Otway Gas Project, the BassGas Project, the Kupe Gas Project, and the Perth, Cooper, Bonaparte and Canterbury basins.

Figure 5.1: Snapshot of retailers' east coast interests and supply in 2017



Box 5.1: About the retailers

EnergyAustralia supplies around 1.7 million electricity and gas customers and has a strong presence in Victoria. In 2017 EnergyAustralia supplied 119 PJ of gas to its customers. EnergyAustralia also has interests in a number of GPG plants in South Australia, NSW and Victoria, and in gas resources in the Gunnedah Basin in NSW.¹⁵²

AGL operates Australia's largest electricity generation portfolio and plays an active role in the gas wholesale market. In 2017 AGL supplied 199 PJ of gas to its customers. Similarly, AGL has interests in a number of GPG plants in South Australia and Victoria. AGL also has interests in gas reserves in the Sydney and Bowen basins in Queensland. In addition to these interests, AGL owns the Newcastle LNG storage facility and the Silver Springs underground storage facility. AGL has also announced that it is considering building an LNG import terminal in Victoria.¹⁵³

Origin is the largest owner of GPG plants in Australia and has a growing customer base, a large portion of which is wholesale customers. Origin supplied 279 PJ of gas to its customers in 2017. Origin has GPG plants in Queensland, South Australia, New South Wales and Victoria. While Origin previously had interests in a number of basins across the east coast, it has recently sold its interests in the Otway, Bass and Cooper basins to Beach Energy.¹⁵⁴ Origin still holds gas reserves in the Surat and Beetaloo basins. Origin also has a 37.5% interest in APLNG (one of the LNG projects in Queensland).

The map on the previous page depicts the range and location of interests for each retailer, in terms of reserves and resources, gas production, gas storage and GPG.

5.3. Analytical approach

The purpose of this preliminary review is to examine how retailers' costs and margins affect the delivered price of gas paid by their customers. Where appropriate, we have followed a similar approach to that taken by the ACCC in its Retail Electricity Pricing Inquiry (REPI) including the use of 'cost stacks' to illustrate our findings (set out in section 5.4 below).¹⁵⁵

Our analysis is based on information provided by the retailers

The ACCC used its compulsory information gathering powers to obtain information about the retailers' gas supply businesses over the four year period from 2014 to 2017.¹⁵⁶

The analysis in this chapter relies heavily on this information, in particular:

- revenue information – for each jurisdiction of the East Coast Gas Market that the retailers supply (i.e. Queensland, New South Wales and the Australian Capital Territory, Victoria, and South Australia) for different customer types
- cost information – including commodity costs, pipeline costs (transmission and distribution), storage costs, and operating costs (see box 5.2 for further information on these costs)
- quantities of gas supplied and obtained
- customer numbers for each jurisdiction and customer type (including the number of customers acquired and lost).

¹⁵² Energy Australia, Fact sheet, November 2017

<https://www.energyaustralia.com.au/about-us/media/fact-sheets>.

¹⁵³ AGL Energy, How we source energy

<https://www.agl.com.au/about-agl/how-we-source-energy>.

¹⁵⁴ Origin Energy, Lattice Energy sale reaches completion, media release, 31 January 2018,

<https://www.originenergy.com.au/about/investors-media/media-centre/lattice-energy-sale-reaches-completion.html>.

¹⁵⁵ ACCC, *Retail Electricity Pricing Inquiry – Final Report*, July 2018, p. 4.

¹⁵⁶ *Competition and Consumer Act 2010* (Cth) s. 95ZK.

The ACCC required the retailers to provide cost, revenue, and quantity information relating only to the operating segment of the retailer that was most directly involved in incurring the cost, receiving the revenue, or obtaining or supplying the gas. This was to avoid receiving information relating to internal transactions within the retailers' overall businesses. The ACCC deliberately sought information that did not derive from transfer prices, except when no other information existed.¹⁵⁷

The retailers were required to provide revenue information for each of the customer types they use when keeping financial records and preparing and lodging financial reports under the *Corporations Act 2001*. The terminology used by the retailers to categorise customers differed, but generally their approaches were similar.

The analysis presented in this chapter uses the following customer types:

- mass market customers – made up of both residential and small to medium sized enterprise (SME) customers. Generally these customers consume less than 1 TJ per year and receive their gas via a distribution network
- commercial and industrial customers – generally these customers consume more than 1 TJ per year and depending on the retailer up to 500 TJ or 1 PJ per year. Depending on the location of these customers, they may receive their supply via a distribution network or directly from a transmission pipeline
- wholesale customers – typically these customers are connected to a transmission pipeline and consume more than 1 PJ per year. This category includes supply to other retailers, the LNG projects, gas powered generators (GPG), and other major gas users. Some large users characterised in other parts of this report as 'C&I' may be treated by the retailers as wholesale customers
- the retailers' own GPGs.

¹⁵⁷ A transfer price is a notional price or other value for the purpose of recording and / or reporting on transactions within its overall business – for example, a retailer may use transfer prices when valuing the gas it supplies to its own gas powered generators.

Box 5.2: Components of retailers' costs

Retailers incur a number of different costs in order to provide their customers with reliable gas supply. The following cost components form the basis of the cost stacks set out in this chapter.

Commodity costs reflect the costs of procuring gas from producers, other suppliers, and the AEMO-operated wholesale markets. During the period, AGL and Origin also sourced gas from their own gas production interests. AGL sourced gas from its Camden gas project in New South Wales, and the Spring Gully project in Queensland. Origin obtained gas from its share of Victoria's Bass Gas and Otway projects, and the Moomba project in South Australia. Origin's interests in these projects have since been acquired by Beach Energy under a sale completed in January 2018.

Pipeline costs reflect the costs of transporting gas on both transmission pipelines¹⁵⁸ and distribution networks¹⁵⁹ and include haulage, compression, storage, interconnection and ancillary charges.

Gas storage facility costs reflect the costs of storing gas in dedicated underground storage or LNG storage facilities. These costs form part of the 'other costs' component in the cost stacks presented in this chapter.

AEMO market costs reflect the costs of participating in one or more of the AEMO-operated wholesale markets – being Victoria's Declared Wholesale Gas Market, the Adelaide, Sydney and Brisbane Short-Term Trading Markets, and the Wallumbilla and Moomba Gas Supply Hubs. These costs also form part of the 'other costs' component in the cost stacks presented in this chapter.

Retailers' operating costs are commonly described as reflecting the retailers' costs to retain customers and acquire new customers, such as costs relating to sales and marketing, and customer service and billing.

Our approach to preparing the retailers' cost stacks

The cost stacks illustrate the contribution of each of the retailer's cost components to the delivered price of gas paid by their customers. The cost stacks also include the retailers' margin – which has been calculated by the ACCC using an approach consistent with how a business' earnings before interest, tax, depreciation and amortisation (EBITDA) is calculated.¹⁶⁰

The delivered price of gas takes into account the total price paid by customers – not just the commodity cost. It has been calculated by dividing the retailers' revenue received from its gas customers by the quantity of gas supplied, and is presented as a dollars per GJ amount (\$/GJ).

The delivered price of gas for each customer type is set out in section 5.4 below.

This chapter presents a cost stack for each year of the 2014-2017 period. Each cost stack reflects an aggregated view of the market, in that the information for individual retailers, states, and customer types has been combined. Costs have been allocated in accordance with the quantity of gas supplied.

5.4. How have the retailers' costs and margins impacted the delivered price of gas paid by their customers?

This section examines how the retailers' costs and margins have impacted the delivered price of gas paid by their customers.

¹⁵⁸ Transmission pipelines transport gas at high pressure from production fields to the city gate(s) (as the entry point to the distribution system in major demand centres and regional areas) and, to large gas users directly connected to the transmission pipelines.

¹⁵⁹ Distribution pipelines, on the other hand, transport gas at a lower pressure from the city gate to commercial and residential customers.

¹⁶⁰ EBITDA, also known as net margin, is a retailer's revenue less the costs of goods sold, less the operating costs.

Quantities of gas supplied by the retailers to their customers

The quantity of gas supplied by the retailers to each customer type, for each year of the period, is set out in chart 5.1 and table 5.1 below.

Chart 5.1: Quantity of gas supplied to each customer type (PJ)

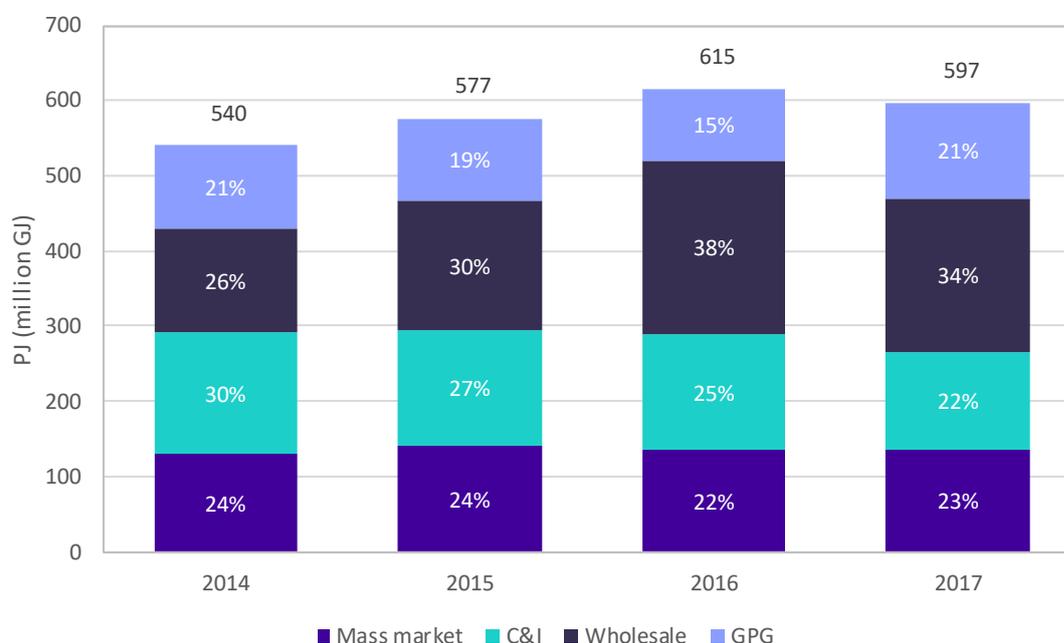


Table 5.1: Quantity of gas supplied to each customer type (PJ)

Customer type	2014	2015	2016	2017	CAGR ¹⁶¹
Mass market	130	141	136	137	1%
C&I	161	154	153	129	-5%
Wholesale	138	171	231	203	10%
GPG	112	111	95	127	3%
All customers	540	577	615	597	3%

Source: ACCC analysis of data supplied by retailers.

Over the period, supply to mass market customers has been steady, both in terms of the quantity supplied (around 130 PJ to 140 PJ) and the proportion of the total quantity supplied (around 23 per cent).

Supply to the retailers' own GPGs fluctuated over the period. The ACCC has previously noted GPG demand is more volatile relative to other types of demand, particularly over the short term, as it is influenced by factors such as weather conditions and the introduction or retirement of other forms of generation in the National Electricity Market.¹⁶²

Supply to wholesale customers made up the largest proportion of total supply in each year except for 2014. The quantity of gas supplied to wholesale customers in 2017 was over 47 per cent higher than in 2014 (rising from 138 PJ to 203 PJ).

¹⁶¹ Compound annual growth rate.

¹⁶² ACCC, *Gas Inquiry 2017-2020 Interim Report*, September 2017, p. 28.

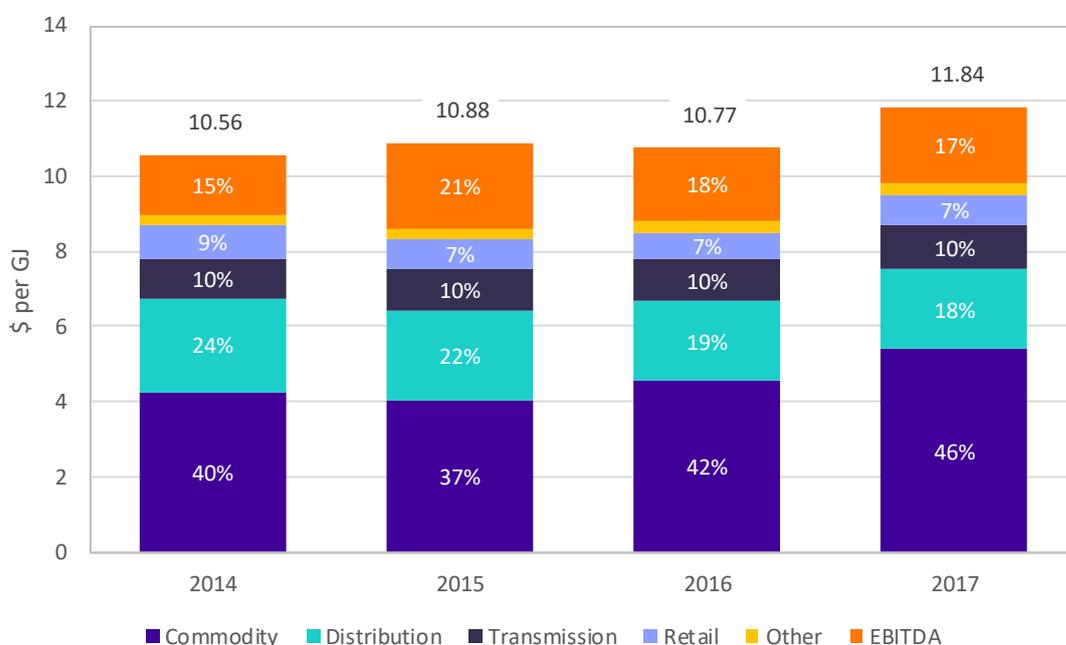
However, as noted above, wholesale customers can include large C&I users, retailers and other suppliers, LNG exporters, and GPGs. We are currently working with the retailers to better understand which of these subcategories have driven the growth in supply to wholesale customers overall.

The quantity of gas supplied to C&I customers declined each year during the period, with 2017 recording the sharpest decline of 15 per cent. There could be several reasons to explain this change, such as customers obtaining gas from other suppliers or implementing measures to reduce their gas requirements. We intend therefore to work with retailers to better understand this change.

Cost stacks

Cost stacks for each year of the period are set out in chart 5.2 below.¹⁶³ Table 5.2 provides the value (in \$/GJ) for each component of the cost stacks and the compound annual growth rate (CAGR) at an aggregate level for the three retailers across the east coast and across all customer types.

Chart 5.2: Cost stacks – the delivered price of gas by each cost component (\$/GJ)



¹⁶³ As noted in section 5.3, cost stacks illustrate the contribution of each of the retailers' cost components to the delivered price of gas paid by their customers. The cost stacks also include the retailers' margin – which has been calculated by the ACCC in accordance with the retailers' EBITDA.

Table 5.2: Cost stacks – the delivered price of gas by each cost component (\$/GJ)

Cost components	2014	2015	2016	2017	CAGR
Commodity	4.27	4.05	4.57	5.41	6%
Distribution	2.48	2.36	2.10	2.10	-4%
Transmission	1.05	1.13	1.12	1.18	3%
Retail	0.90	0.77	0.73	0.79	-3%
Other	0.26	0.27	0.29	0.31	5%
EBITDA	1.60	2.29	1.96	2.05	6%
Total (delivered price of gas)	10.56	10.88	10.77	11.84	3%

Source: ACCC analysis of data supplied by retailers.

Note: In this chart, 'retail' costs refer to the retailers' operating costs, while 'other' costs include costs associated with storage and the costs of participating in AEMO-operated Wholesale Markets. Not all cost categories presented in this chart are applicable to all the customer segments – for example, retailers would not typically incur distribution costs in supplying wholesale customers.

As chart 5.2 shows, the average delivered price of gas (i.e. across all customer types) fluctuated over the period, ranging from \$10.56/GJ in 2014 to \$11.84/GJ in 2017.

The commodity cost component accounted for the greatest share of the delivered price over this period, accounting for between 37 and 46 per cent of the delivered price of gas. After declining somewhat in 2015, the commodity cost component rose in the following two years. In quantity-weighted terms, it increased over 33 per cent from \$4.05/GJ in 2015, to \$5.41/GJ in 2017.

The distribution cost component accounted for the second largest share of the delivered price over the period, accounting for between 18 per cent and 24 per cent of the delivered price of gas. In quantity-weighted terms, the distribution component fell from \$2.48/GJ in 2014 to \$2.10/GJ in 2017.

While the share of distribution charges appears to have fallen over the period, some care should be taken when interpreting this result because it has been calculated on an aggregated basis by dividing the retailers' total distribution costs by the total quantity of gas supplied by the retailers. The total quantity of gas supplied by retailers includes the quantity of gas supplied to customers located in the distribution network (e.g. mass market customers and some C&I customers) and customers located outside the distribution network (e.g. GPGs, wholesale customers and some C&I customers). Some of the decline may therefore be attributable to the significant increase in the quantity of gas supplied to wholesale customers in 2016 and 2017 rather than any changes in the prices for distribution services over the period.

The retailers' average margin (shown as EBITDA in chart 5.2 and table 5.2 above) accounted for the third largest share of the delivered price of gas over the period. As a proportion of the delivered price of gas, the retailers' average margin rose from 15 per cent in 2014 to 21 per cent in 2015, before falling to 17 per cent in 2017. In quantity weighted terms, the retailers' margins increased over 28 per cent from \$1.60/GJ in 2014 to \$2.05/GJ in 2017.

We emphasise that these are highly aggregated preliminary results, which require further examination before final conclusions can be made. Separate analysis indicates that the margins vary across the retailers, and for particular customer types and locations. Also, the EBITDA measure does not account for the risks faced by the retailers, or allow for a return on capital. The ACCC will examine these matters in further detail as part of the inquiry.

The transmission cost component accounted for the fourth largest share of the delivered price, accounting for around 10 per cent of the delivered price of gas over the period.¹⁶⁴ In quantity weighted terms, the transmission cost component trended upwards over the period, increasing from \$1.05/GJ in 2014 to \$1.18/GJ in 2017 (an increase of around 12 per cent).

There are some indications in the data we have examined that transmission costs in Victoria may be materially lower than the transmission costs incurred outside of Victoria. There could be a number of reasons for this, such as differences in pricing and carriage arrangements, the unique physical characteristics of Victoria's transmission system, and the large quantities of gas transported by the system.

The ACCC will consider these matters in more detail as part of the inquiry.

The retail cost component accounted for the fifth largest share (or second smallest) of the delivered price. In quantity weighted terms, this cost component accounted for around seven per cent of the delivered price of gas (around \$0.73 to \$0.79/GJ) in every year except for 2014, when it accounted for nine per cent (around \$0.90/GJ). The total cost incurred by each of the retailers, in dollar terms, was comparable over the period.

The final cost component, 'other costs', accounted for the smallest share of the delivered price over the period. This category, which includes AEMO market fees and charges, and costs relating to gas storage facilities, accounted for up to three per cent of the delivered price of gas over the period (around \$0.30/GJ).

Applying the findings of the cost stack analysis to particular customer types and jurisdictions

The cost stack analysis has been prepared using information for all customer types, across all jurisdictions of the East Coast Gas Market, for the three retailers combined.

There are limitations, however, in applying the values and proportions of the individual cost components to particular customer types. This is because each customer will have a different impact on both the types of costs incurred by a retailer, and also the magnitude of these costs. A good example of this can be found in the distribution costs. When supplying mass market customers and C&I customers that are located in a gas distribution network, retailers will have to pay distribution charges. However, when supplying other customers that are directly connected to a transmission pipeline (e.g. wholesale customers, GPGs and some C&I customers) retailers will not have to pay these charges.

The effect of these differences can be seen in chart 5.3 below, which shows the delivered price of gas paid by each customer type at an aggregate level for the three retailers across the east coast.

¹⁶⁴ This proportion will vary for different customer types. For customers that are supplied from a transmission pipeline (i.e. outside of a distribution network) transmission costs can account for a greater share of their delivered price of gas.

Chart 5.3: The delivered price of gas for each customer type (\$/GJ)

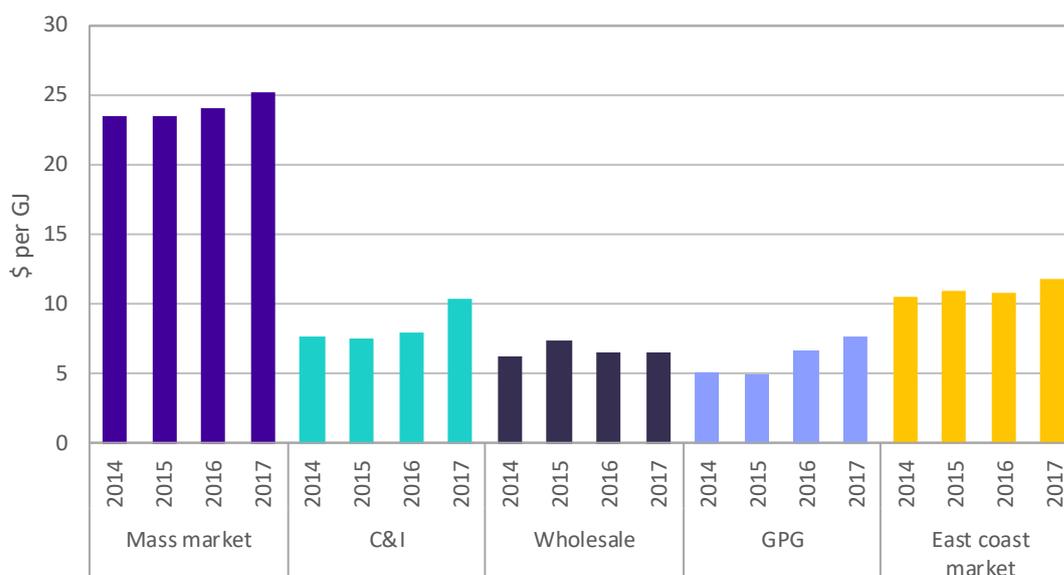


Table 5.3: The delivered price of gas for each customer type (\$/GJ)

Delivered price of gas	2014	2015	2016	2017	CAGR
Mass market	24	23	24	25	2%
C&I	8	8	8	10	8%
Wholesale	6	7	6	6	2%
GPG	5	5	7	8	11%
Quantity weighted average	10	11	11	12	3%

Source: ACCC analysis of data supplied by retailers.

It also appears that the location of a particular customer may also have an impact on the retailers' costs incurred, as will each retailer's market share in each customer segment.

The ACCC intends to examine the retailers' costs and margins in greater detail to understand what drives the prices paid by different customer types in particular jurisdictions.

5.5. Preliminary conclusions and future work

The ACCC's preliminary examination of retailer margins suggests that continued focus and consideration is required to fully understand and test the cost components that make up the delivered price of gas paid by all customers. In particular, the ACCC's next stage of examination will explore individual customer types and jurisdictions.

In this way the ACCC intends to shed further light on the retail market and in particular the drivers behind the costs and margins for the three largest retailers.