Gas inquiry 2017–2020

Interim report

July 2019

accc.gov.au

Australian Competition and Consumer Commission
23 Marcus Clarke Street, Canberra, Australian Capital Territory, 2601

Contents

Acronym

ACQ	annual contract quantity
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Security Mechanism
BCM	billion cubic metres
CCA	*Competition and Consumer Act 2010* (Cth)
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DAC	depreciated actual cost
DES	delivered ex-ship
DORC	depreciated optimised replacement cost
DWGM	Declared Wholesale Gas Market
EBIT	earnings before interest and taxes
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
GSG	Gas Supply Guarantee
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
IT	Information Technology
JCC	Japanese Customs-Cleared Crude
JKM	Japan 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
MOU	Memorandum of Understanding
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
PPI	Producer Price Index
QLD	Queensland
RCM	recovered capital method
RCV	recovered capital value
REPI	ACCC's Retail Electricity Pricing Inquiry
RIS	Regulation Impact Statement
SA	South Australia
SGP	Surat Gas Project
STTM	Short-term trading market
TJ	Terajoule
UK	United Kingdom
US	United States
VIC	Victoria
WA	Western Australia
WACC	weighted average cost of capital
WAP	weighted average prices

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
AIE	Australian Industrial Energy
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 Proprietary Company) and Billiton
CIS	Commonwealth of Independent States
CNOOC	China National Offshore Oil Corporation
COAG	Council of Australian Governments
EIA	Energy Information Agency (US)
ERA	Economic Regulation Authority
ESC	Essential Services Commission
FERC	Federal Energy Regulatory Commission (US)
GBJV	Gippsland Basin Joint Venture
GLNG	Gladstone LNG
GMRG	Gas Market Reform Group
IPART	Independent Pricing and Regulatory Tribunal
ICE	Intercontinental Exchange
NOPTA	National Offshore Petroleum Titles Administrator
PWC	Power and Water Corporation
QCLNG	Queensland Curtis LNG Project
QGC	QGC Pty Limited, previously Queensland Gas Company
QIC	Queensland Investment Corporation
RBA	Reserve Bank of Australia

RLMS	Resource and Land Management Services
SCO	COAG's Senior Committee of Officials
SEA	Shell Energy Australia
SEC	Securities and Exchange Commission (US)
SGH	Seven Group Holdings
SPE-PRMS	Society of Petroleum Engineers-Petroleum Resources Management System
Pipelines	
AGP	Amadeus Gas Pipeline
BWP	Berwyndale to Wallumbilla Pipeline
CGP	Carpentaria Gas Pipeline
CRP	Central Ranges Pipeline
CRWPL	Comet Ridge to Wallumbilla Pipeline Loop
CWP	Central West Pipeline
DDP	Darling Downs Pipeline
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
PCA	Port Campbell to Adelaide Pipeline
PCI	Port Campbell to Iona Pipeline
QGP	Queensland Gas Pipeline
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
VTS	Victorian Transmission System
WGP	Wallumbilla Gladstone 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.

December 2018 report: The ACCC's fifth interim report, published in December 2018, 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.

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.

Export demand: The quantity of Australian gas demanded by overseas buyers.

Free on-board price: The price of gas loaded on a ship at a port connected to an LNG plant.

Liquefaction: The process of liquefying natural gas.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG netback price: A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

LNG train: A liquefied natural gas plant's liquefaction and purification facility.

Load factor: measures the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the annual contract quantity.

Most favoured nation (MFN) clauses: Clauses that give the pipeline capacity holder a right to receive the same price as that payable by another shipper for an equivalent cheaper service.

Part 23

> **Part 23 framework**: The information disclosure and arbitration framework for non-scheme pipelines set out in Chapter 6A of the National Gas Law and Part 23 of the National Gas Rules, which came into effect on 1 August 2017.
>
> **Non-scheme pipelines (or Part 23 pipelines**): A pipeline that is not subject to either full or light regulation, but is subject to the information disclosure and arbitration framework in Part 23 of the National Gas Rules.
>
> **Recovered capital values**: An aspect of the Part 23 framework intended to provide an indication of the extent to which the costs incurred in constructing and augmenting a pipeline have been recovered.

Pipeline transportation services

As available transportation service: A service that allows the transportation of gas on an 'as available' basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

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

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

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

Loan service: A service that allows users to "borrow" gas from a pipeline, which in practice involves withdrawing more gas from a pipeline than what is injected on a particular day.

Reserves and resources

Reserves: Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

1P (proved) reserves: Commercially recoverable reserves with at least a 90 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

2P (proved and probable) reserves: Commercially recoverable reserves with at least a 50 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

3P (proved and probable and possible) reserves: Commercially recoverable reserves with at least a 10 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

Contingent resources: quantities of gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

Prospective resources: Estimated quantities associated with undiscovered gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated and an estimate made of quantities that would be recoverable under appropriate development projects.

Retailer: For the purpose of this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy and Shell Energy Australia.

Revenue rebate clauses: Clauses that give a pipeline capacity holder the right to be paid some or all of the revenue that a pipeline operator derives from supplying a specified pipeline service to another party.

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.

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 or prospective user of pipeline services.

Unfulfilled offer: A written offer for supply of gas that does not result in an agreement to supply gas.

Units of Energy

Joule—a unit of energy in the International System of Units

Gigajoule (GJ)—a billion (10^9) joules

Terajoule (TJ)—a trillion (10^{12}) joules

Petajoule (PJ)—a quadrillion (10^{15}) joules

Million British Thermal Units (MMBtu)

Overview

This is the seventh 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]

Addressing the longer-term concerns in the East Coast Gas Market requires attention at all points in the supply chain. The ACCC has long advocated the need for an increase in supply and diversity of suppliers, particularly in the Southern States, and has made a range of recommendations to improve the transparency and operation of the East Coast Gas Market. Further efforts are also required in respect of gas transportation and storage, and in retail markets.

This report continues the ACCC's long standing reporting on the supply-demand balance and prices paid for gas and gas transportation in the East Coast Gas Market. New analysis on retailer costs and margins and a detailed review of recent regulatory reform in respect of gas pipelines is also included in this report.

In the December 2018 report, the ACCC reported on the gas supply outlook in the East Coast Gas Market in 2019. The ACCC found that there was unlikely to be a gas supply shortfall in 2019 based on the supply and export forecasts from producers and the Australian Energy Market Operator's (AEMO's) domestic demand forecasts.

Compared to 2019, the likelihood of a gas supply shortfall in the East Coast Gas Market in 2020 is lower, primarily because:

- east coast producers expect to produce an additional 113 PJ (1988 PJ in total)
- AEMO forecasts consumption by gas powered generators (GPG) to be lower by 16 PJ (72 PJ in total), and
- LNG producers expect to have an additional 92 PJ in excess of their contractual commitments (168 PJ in total), which will likely act as a buffer should domestic demand on the east coast be higher, or gas production lower, than currently forecast.

The supply forecast provided by gas producers and AEMO's domestic demand forecast indicate that there will be sufficient gas produced in the Southern States to meet demand. However, the supply-demand balance in the Southern States for 2020 is tight and can be uncertain because it is subject to:

- the quantity of gas produced in the south, particularly in the Cooper Basin, that will flow into Queensland, and
- realised demand for gas from gas powered generators (GPG), which is difficult to predict.

In 2018, prices offered for supply of gas in 2020 increased, coinciding with rising expectations of LNG netback prices for 2020.

Our most recent analysis shows that prices offered by gas producers in Queensland for 2020 supply appear to have fallen at the same time as this year's decline in the expected LNG netback prices for 2020. However, it appears that the prices offered by suppliers in the Southern States, particularly by retailers, have not. The drivers behind this are unclear.

[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.

In the first quarter of 2019, the prices offered by retailers to C&I gas users in the East Coast Gas Market have remained in the $10–12/GJ range.[2]

Following our initial examination in the December 2018 Interim Report, the ACCC has conducted a detailed review of the costs and margins of the three largest gas retailers (AGL, EnergyAustralia and Origin) on gas sales to mass market and small and large C&I customers.

The average portfolio margins collectively earned by these retailers over 2014–2018 appear well in excess of what we would expect. However, this may be due to the cyclical nature of gas markets, with a number of low-priced legacy contracts with producers keeping the retailers' average costs down (relative to gas market prices that they sell gas at). If margins were estimated on the basis of a retailer's cost of acquiring additional gas and selling it under current market conditions, the margin for that specific supply of gas would likely be lower.

The ACCC will conduct further monitoring and analysis to better understand the extent to which high margins are being influenced by cyclical factors such as these and whether there are long term structural issues and a lack of competition.

Our analysis for this report has uncovered a significant shift in the C&I market or market segment, with two of the three largest gas retailers losing considerable share of the market to producers and new market entrants.

There has been a difference in experiences between small and large C&I users, with the latter reporting a willingness of producers and retailer to engage and negotiate. This is in contrast to smaller users who can sometimes just receive one offer.

While provision of transportation services is becoming more dynamic, most pipeline tariffs remain high. The ACCC's 2015 inquiry found that the majority of transmission pipelines on the east coast were using their market power to engage in monopoly pricing.[3] The ACCC has observed a decrease in excessive pricing for as available and interruptible transportation services. Although the prices for firm forward haul services on most pipelines have not fallen from the levels observed in the 2015 inquiry, in some cases they have increased significantly.

As a part of this report the ACCC has conducted a review of the operation of the information disclosure and arbitration framework ('Part 23') (set out in Chapter 6A of the National Gas Law and Part 23 of the National Gas Rules), which was introduced two years ago. In short, Part 23 appears to be working as intended and there are signs that it is having a positive effect on pipeline prices and the contracting environment. However, to the ACCC's disappointment, some pipeline operators do not appear to be taking their disclosure obligations seriously and are continuing to exploit information asymmetries to the detriment of shippers. The ACCC recommends a range of improvements to the framework to address these issues (see section 6.7).

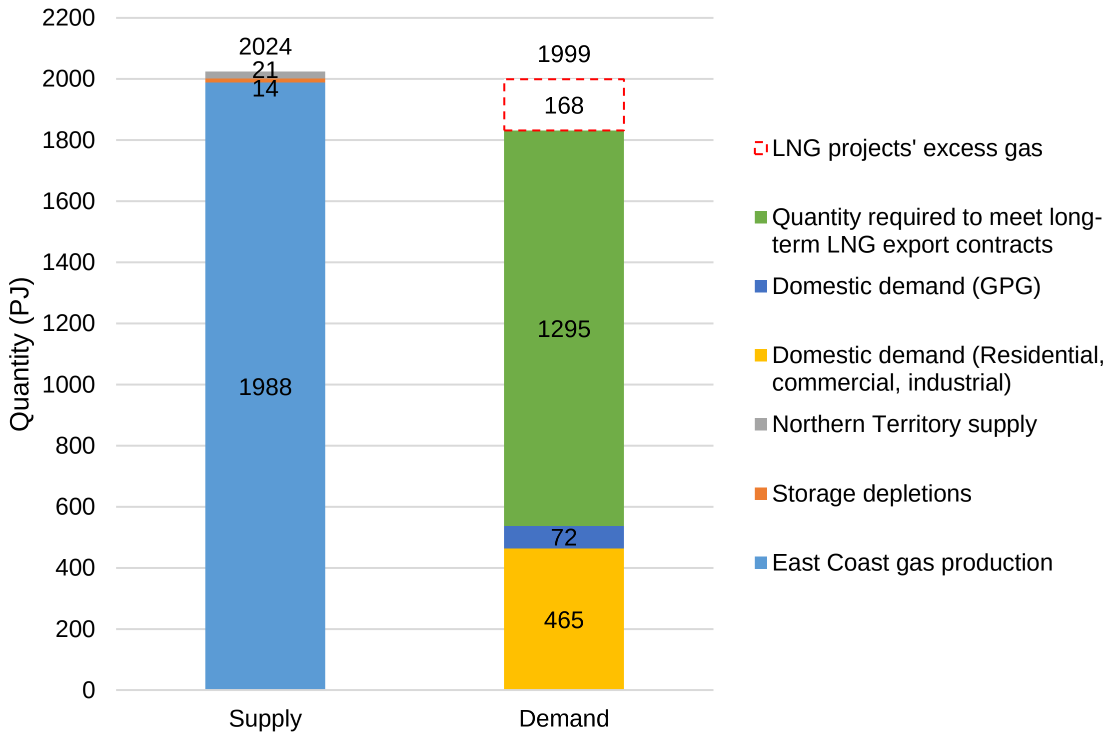
2 Unless otherwise specified, all references to 'prices' in this report are references to gas commodity prices, which do not include separate transportation or other ancillary charges.

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

Sufficient gas supply is expected in 2020 to meet forecast demand in the East Coast Gas Market

The immediate supply-demand outlook in the East Coast Gas Market has improved since our December 2018 report. Under current projections, there is unlikely to be a gas supply shortfall in 2020 (chart 1).

Chart 1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2020



Source: ACCC analysis of data obtained from producers and of data from AEMO's March 2019 GSOO.

Note: Totals may not add up due to rounding.

The key changes in forecasts since the ACCC's December 2018 report are:

- producers in the east coast expect to produce 1988 PJ in 2020, compared to 1875 PJ in 2019, which is largely due to an increase in expected production by Queensland LNG producers and Victorian producers in the Gippsland Basin
- AEMO expects GPG to consume 72 PJ of gas in 2020, compared to 88 PJ in 2019
- LNG producers expect to require 1295 PJ to meet their commitments under long-term export contracts, compared to 1281 PJ in 2019, and
- LNG producers expect to have 168 PJ of gas in excess of their contractual commitments, compared to 76 PJ in 2019.

The supply outlook in the Southern States for 2020 can be and is subject to:

- The quantity of gas produced in the south, particularly in the Cooper Basin, that will flow into Queensland. A significant portion of the Cooper Basin production relates to gas acquired by a single gas retailer, which contributes to the retailer's total east coast portfolio. If a significant portion of this gas is delivered into Queensland, this would significantly tighten the supply-demand balance in the south.

- Realised demand for gas from GPG, which is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, availability of renewable generation, unexpected retirement of generation or unplanned outages).

The Queensland LNG producers could sell the 168 PJ of excess gas they expect to have domestically or overseas. 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 on reasonable terms to the domestic market before exporting it, in the event a supply shortfall arises in 2019 or 2020.[4]

As a result, their 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 effectiveness of this buffer will depend on whether the LNG producers offer this gas to buyers in the East Coast Gas Market in a way that meets the requirements of buyers. If the LNG producers offer gas in large quantities that have to be taken over a short time period, there may not be enough domestic buyers who are able to consume, transport and/or store this gas within the time constraints.

As at April 2019, the LNG producers contracted to supply 176 PJ to the domestic market in 2020, which is less than they expect to take out (203 PJ). The 176 PJ represents 33 per cent of expected 2020 domestic demand, compared to the 37 per cent (205 PJ) that the LNG producers had committed to supply in 2019 by the same point last year.

At least in part, this reduction reflects the changing dynamics in the East Coast Gas Market, as there has been an increase in supply from other producers in the market. As at end of April 2019, non-LNG producers contracted 380 PJ of gas to the domestic market for supply in 2020, which is 45 PJ more than the quantity they had contracted at same time last year for supply in 2019. These producers still have around 100 PJ of uncontracted gas for supply in 2020.

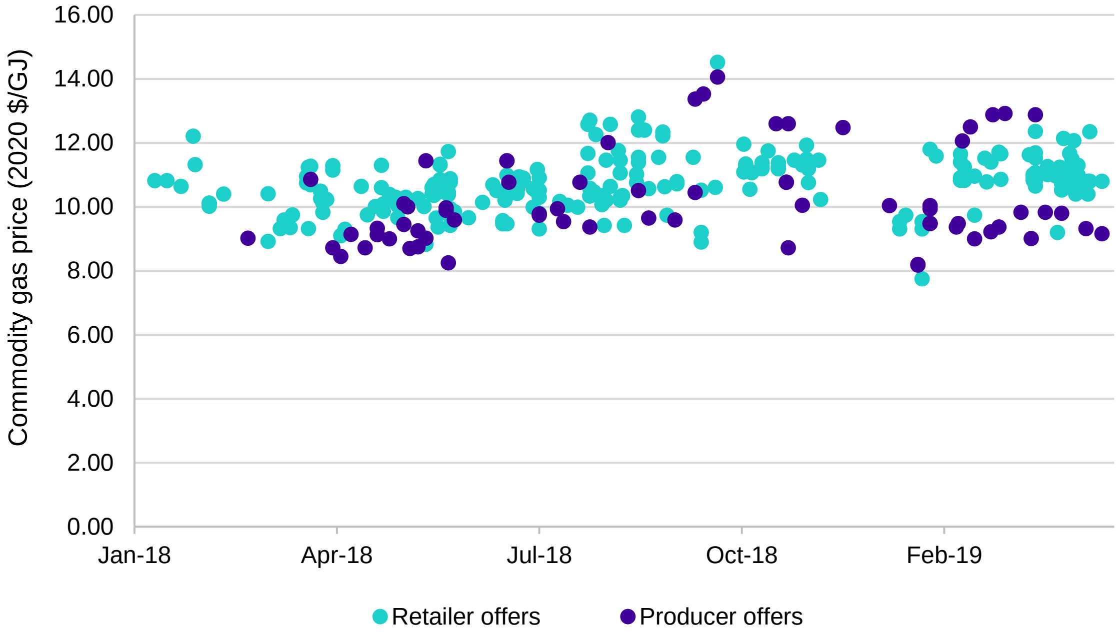
Many C&I users will pay at least $10/GJ for supply in 2020

In the April 2019 report, we observed that prices in offers for supply in 2020 increased over the course of 2018, coinciding with rising expectations for Asian LNG spot prices. In the second half of 2018, most offers for gas supply in 2020 were above $10/GJ.

Chart 2 shows how this trend has evolved in the first quarter of 2019.

[4] 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.

Chart 2: Gas commodity prices offered for 2020 supply in the East Coast Gas Market



Source: ACCC analysis of offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ and a term of at least 12 months.

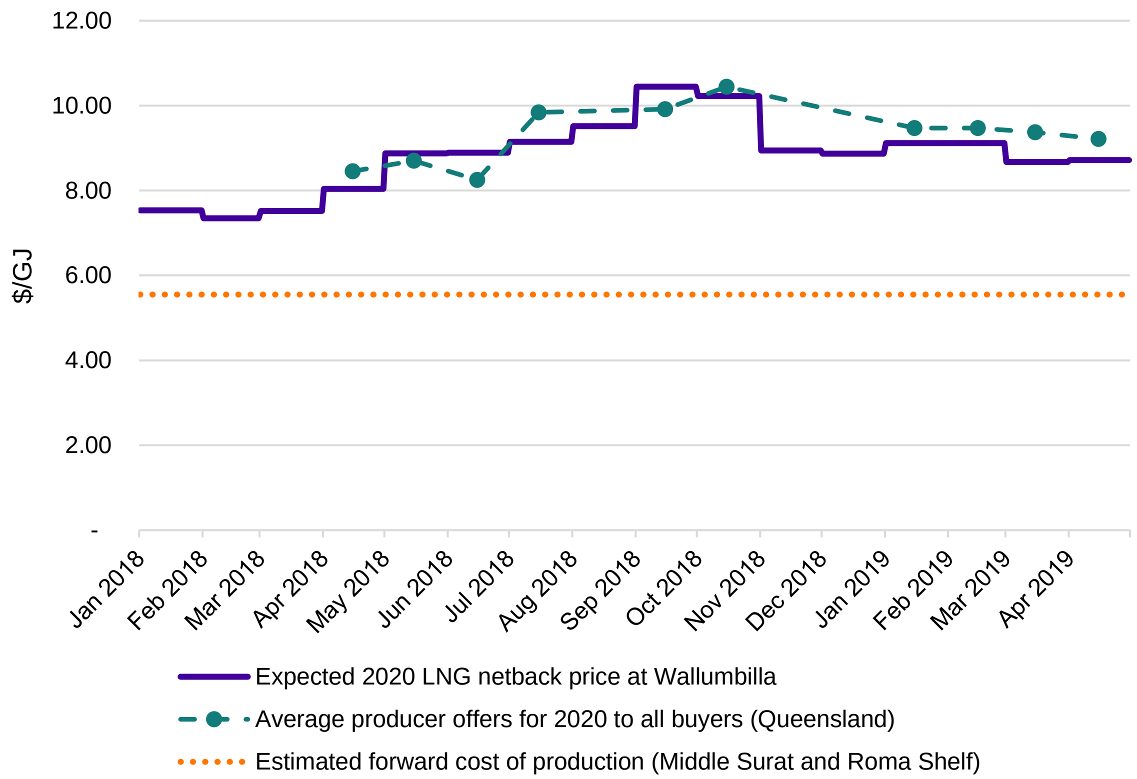
The chart shows that while prices offered by gas producers largely fell below $10/GJ in the first quarter of 2019, prices offered by retailers, mostly to C&I gas users, have remained in the $10-12/GJ range.

Recent price offers have fallen in Queensland with declining netback, but this has not occurred in the south

Over the past nine months, there has been a significant shift in expectations of LNG spot prices. After reaching a peak of almost $11/GJ in October 2018, the expected 2020 LNG netback prices at Wallumbilla fell under $9/GJ by the middle of April and just over $8/GJ by mid-June 2019.

In the first quarter of 2019, the averages of prices offered by producers in Queensland for gas supply in 2020 appear to have fallen broadly in line with expected 2020 LNG netback prices, as shown in chart 3.

Chart 3: Averages of monthly gas commodity prices offered by Queensland producers for 2020 supply against contemporaneous expectations of LNG netback prices



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

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

The averages of prices offered by retailers in the Southern States however appear quite high relative to the expected LNG netback prices. The drivers behind this are unclear.

Data available to the ACCC indicates that sufficient gas is expected to be produced in the south to meet demand in the south. It is uncertain, however, how much gas from the Cooper Basin will flow south and the how much will be needed by GPG. Other factors may also be contributing to the prices being offered in Southern States. Ultimately, more low-cost supply is needed in the Southern States to put downward pressure on gas prices.

Australian delivered gas prices compared to prices paid overseas

Over the past few years, there has been some speculation that Australian gas users are paying more for gas produced in Australia than the overseas buyers. To test whether this was the case, the ACCC engaged S&P Global Platts to prepare a report on delivered gas prices paid by C&I gas users in a range of countries around the world.

The Platts report shows that the delivered prices that the C&I gas users in the East Coast Gas Market pay are lower than the delivered prices paid by C&I gas users in Asian countries that purchase Australian LNG (e.g. South Korea and China). This is to be expected and reflects the costs involved in liquefying gas, shipping it to another country, regasifying it and then transporting it to end-users location.

However, the Platts report shows that delivered prices paid by C&I gas users in the east coast are higher than the prices paid by C&I gas users in other gas exporting countries (e.g.

US and Canada). This reflects the unique characteristics of the East Coast Gas Market, particularly the tight supply-demand balance, weak competition, high gas production costs, high transmission prices and close linkage to the international LNG markets.

The three major gas retailers earned higher than expected average margins for 2014–2018, but overall have lost significant C&I market share

The ACCC has conducted a detailed review of the costs and margins of the three largest gas retailers (AGL, EnergyAustralia and Origin) over the period from 2014 to 2018.

The retailers supply gas to a range of customers across the east coast. For the purpose of this report, the ACCC has focused on two customer segments:

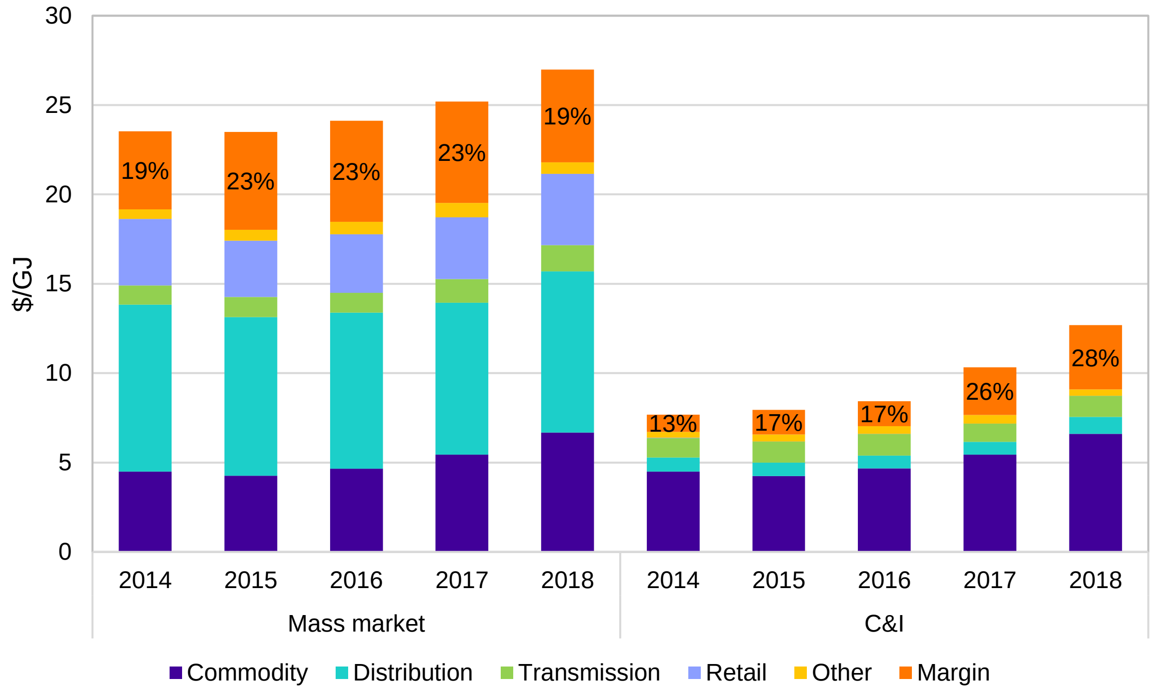
- mass market (residential and small to medium enterprises), and
- C&I gas users (both small and large C&I users).[5]

The ACCC obtained information from the three retailers relating to the costs incurred, and revenues received, in supplying mass market and C&I gas customers. Chart 5 presents the combined results for the east coast portfolios of the three retailers.

[5] While much of the ACCC's inquiry has focused on the wholesale gas market and large C&I gas users (those that consume more than 500 terajoules per year), our analysis of margins for both the mass market and C&I is broader. C&I gas customers in this analysis:

- consume more than one terajoule per year, and
- exclude a very small number of users that are classified by major retailers as wholesale customers. The highest annual quantity of gas supplied to these customers over 2014–2018 was less than 2 per cent of total supply by the major retailers to C&I users in the same year.

Chart 5: The delivered price of gas[6] paid by mass market and C&I customers of AGL, EnergyAustralia and Origin, broken down by each cost component and the retailers' margin[7]



Source: ACCC analysis of information provided by AGL, Origin Energy and EnergyAustralia.

Note: The distribution costs presented in this chart for C&I customer segment are not applicable to all C&I customers—some of the C&I customers may be receiving gas directly from a transmission pipeline, so retailers would not incur distribution costs in supplying those customers.

Chart 5 shows that the three large retailers collectively earned high average margins in supplying both the mass market and C&I customer segments in the period from 2014 to 2018. However, these results are aggregated and the costs incurred and the average margins earned differ between these retailers, including across customer types and locations.

The average margins that the three large retailers collectively earned from sales to mass market customers ranged from 19 to 23 per cent over the period. While average delivered prices to mass market customers increased in 2017 and 2018, there was a commensurate increase in the average gas commodity costs of the three retailers.

The average margins that the three large retailers collectively earned from sales to C&I gas customers increased from 13 per cent in 2014 to 28 per cent in 2018. The average delivered prices to C&I gas customers increased in every year of this period. The average gas commodity costs of the three retailers increased at a slower rate than prices did during this period, resulting in significant increases in average margins, particularly in 2017 and 2018.

The average margins that the three large retailers collectively earned from sales to mass market and C&I gas customers over 2014–2018 appear well in excess of what the ACCC would expect.

6 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.

7 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.

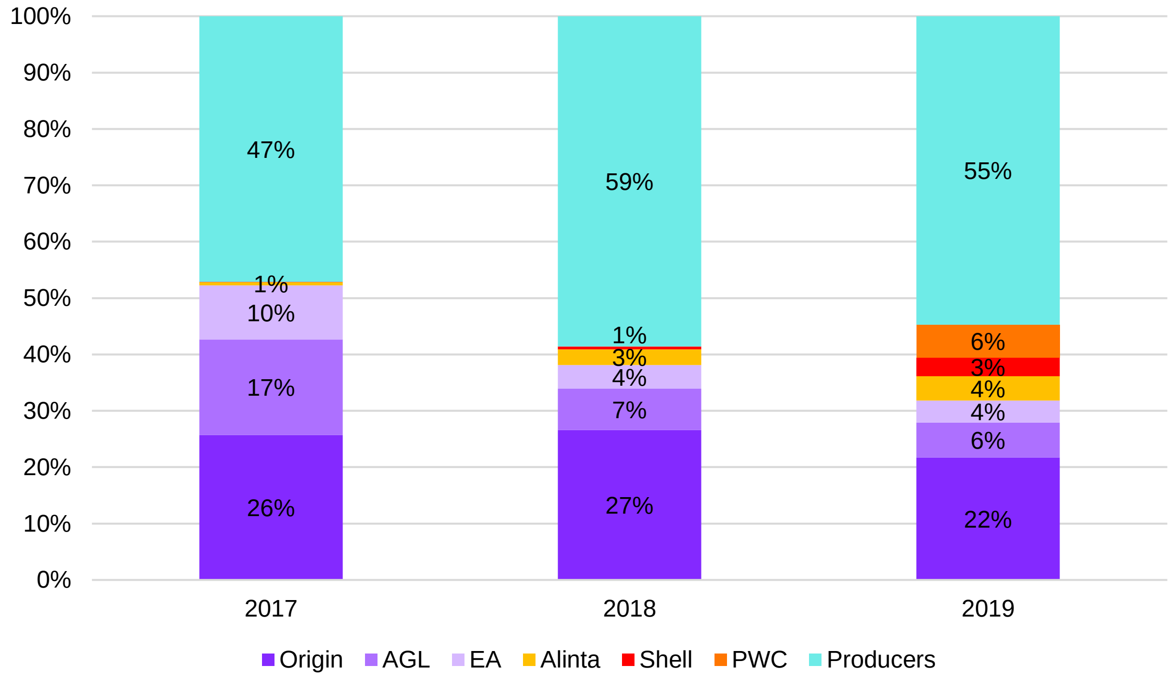
In part, the high margins for C&I customers may be due to the retailers' average costs of gas increasing more slowly (due to legacy contracts) than the prices at which retailers can resell gas in the current market. And while the retailers generally take a portfolio approach to buying and selling gas, if margins were estimated on the basis of a retailer's cost of acquiring marginal gas to supply to a particular customer under current market conditions, then the margin for that supply would likely be lower.

Significant change in gas seller market shares

We have also observed a significant shift in the relative market shares of the three major retailers in supplying C&I customers over the past several years.

Chart 6 below shows the C&I market shares of the major retailers, smaller and new entrant retailers, and producers between 2017 and 2019.

Chart 6: C&I market shares of retailers and producers



Source: ACCC analysis of information provided by suppliers.

Note: Market shares are relative to the retailers shown in the chart and the producers from which the ACCC has collected information for this report. The chart excludes supply to C&I users by other suppliers. Data for 2019 is based on the quantity of gas contracted with C&I users as at April 2019.

Chart 6 shows that the C&I market shares of the major retailers fell from 52 per cent in 2017 to 32 per cent in 2019, with this decline being mostly driven by a decline in the market shares of AGL and EnergyAustralia. The chart also shows that a greater share of C&I demand is being supplied by producers, while supply to C&I users by smaller or new entrant retailers has also increased over recent years.

Notwithstanding these recent changes in the market, the ACCC is concerned with the high margins it has found in the major retailers' supply to both mass market and C&I customers. We will continue to monitor and analyse retailer margins to understand more fully the extent to which high margins for mass market and C&I customers reflect the cyclical nature of the sector (including the effect of low-cost legacy contracts) or longer term structural and competition issues.

C&I gas users are adapting but experiences differ between small and large C&I users

Current gas prices remain challenging for many trade exposed C&I gas users. Some of these C&I gas users have informed the ACCC that they cannot pass on their rising costs, which have doubled or tripled in the past few years, to their customers because they would become uncompetitive with their overseas rivals. Instead, these C&I gas users must absorb higher gas costs and find strategies to mitigate the effects on their business.

The majority of C&I gas users surveyed[8] have implemented gas-reduction strategies, including energy efficiency improvements and fuel switching, and continue to explore further opportunities to cut gas use. For example, Australian Paper is moving forward with an energy-from-waste plant after successful completion of a $7.5 million feasibility study.[9] Another C&I gas user has converted one boiler from gas to coal and another from gas to woodchips.

Many C&I gas users have altered their approach to sourcing gas. Whereas in the past they may have simply rolled over their supply contract with a retailer upon expiry, they are now looking for gas from a diverse range of supply sources and, when required, contracting their transportation requirements directly. Some have procured gas directly from producers, some have engaged in discussions with the entities considering constructing LNG import facilities and some have been using short-term trading markets to supplement their supply.

Notably, large C&I gas users (over 1 PJ/a) and small gas users seeking gas report different market experiences. Larger C&I gas users generally noted a willingness by producers and retailers to engage and negotiate, with users receiving a number of responses to a request for prices. Smaller C&I gas users that have recently been active in the market for 2020 supply reported fewer suppliers making offers. In some cases users received just one offer.

Despite these efforts, a number of C&I gas users have advised the ACCC that their business operations are unsustainable in the long-term. As a result, some are postponing capital expenditure, reducing headcount or pay increases and deferring investments or expansions. A number of C&I gas users have expanded operations overseas instead of increasing development in Australia, citing significantly lower gas prices overseas (particularly in the US).[10]

Some have gone a step further. In May 2019, Dow Chemicals announced plans to shut its manufacturing plant in Melbourne, citing rising gas prices as one of the main reasons for its decision.[11] This follows the closure of RemaPak, a Sydney-based producer of polystyrene coffee cups, and Claypave, a Queensland-based brick and paving manufacturer, in the first quarter of 2019.

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8 These C&I gas users are located predominantly in the Southern States and have a combined annual consumption of around 80 PJ/a, which represents almost half of the C&I demand in the east coast.

9 ABC News, *Australian Paper to proceed with Victorian-first energy-from waste project*, 7 February 2019, https://www.abc.net.au/news/2019-02-07/victorian-first-energy-from-waste-project-gets-green-light/10791686.

10 The Financial Review, *Brickworks pays $151m for US brick manufacturer Glen –Gery*, 23 November 2018, https://www.afr.com/business/brickworks-pays-151-million-for-us-brick-manufacturer-glengery-20181123-h188sr; Incitec Pivot Limited, *Supporting our Businesses with global manufacturing capabilities*, 3 April 2019, https://www.incitecpivot.com.au/about-us/our-businesses/global-manufacturing-capabilities accessed 6 June 2019.

11 Australian Financial Review, ***RemaPak decline illustrates 'trauma' for gas based manufacturers***, 21 January 2019, https://www.afr.com/business/manufacturing/remapak-decline-illustrates-trauma-for-gasbased-manufacturers-20190121-h1aa3r; Adam Ward, *Press release: Claypave creditors place company into liquidation*, 30 April 2019, https://worrells.net.au/press-release-claypave-creditors-place-company-into-liquidation/; The Sydney Morning Herald, *Altona Site to Shut: union sounds jobs alarm on gas crisis,* 28 May 2019, https://www.smh.com.au/business/companies/altona-site-to-shut-union-sounds-jobs-alarm-on-gas-crisis-20190528-p51s2s.html.

Many other manufacturers are continuing to operate because their capital costs are sunk. They will have to make critical decisions on their future operations when material capital re-investment in maintenance, replacement or upgrade of their plants is required.

The provision of pipeline services is becoming more dynamic

The ACCC's 2015 inquiry found that the majority of transmission pipelines on the east coast were using their market power to engage in monopoly pricing. Since the 2015 inquiry, many gas transmission pipelines have been subject to a number of market based and regulatory changes, such as the introduction of the information disclosure and arbitration framework and the capacity trading reforms. These changes are influencing pipeline operators' contracting activities and the prices payable for transportation and pipeline storage services.

As previously reported, the changes occurring in the broader market have prompted a significant increase in the number of shippers seeking shorter-term gas transportation agreements. There has also been an increase in the demand for as available and interruptible transportation and pipeline storage services and some pipeline operators are developing new services to meet changing customer needs. A greater number of C&I gas users and smaller retailers are also now contracting directly with pipeline operators. In a number of cases, larger C&I gas users have been able to negotiate substantial discounts from the pipeline operators' standing prices, however, smaller C&I gas users have not been as successful.

On the pricing side, there are signs that recent reforms and market developments are leading to positive outcomes. The incidence of excessive pricing of as available and interruptible transportation services has, for example, decreased since the ACCC's 2015 inquiry and is expected to fall further following the recently introduced capacity trading reforms. The first arbitration under Part 23 has also resulted in prices on the Tasmanian Gas Pipeline (TGP) falling significantly, and prices on the Carpentaria Gas Pipeline (CGP) have also fallen.

Despite these positive signs, the prices payable for firm forward haul services on most pipelines have not fallen from the levels observed in the 2015 inquiry, and in some cases have increased significantly. The ACCC intends therefore to continue to examine the contracting activities of pipeline operators and consider the cost reflectivity of prices.

Part 23 appears to be working but the ACCC recommends improvements to further empower shippers

In general, the ACCC is of the view that Part 23 is working as intended. In particular, there are signs (outlined above) that Part 23 is having a positive effect on pipeline prices and the contracting environment. The ACCC has not found evidence to suggest that the architecture of Part 23 is fundamentally flawed, but some elements require strengthening to address the issues we have identified.

The effectiveness of the Part 23 is critically dependent on the provision of accurate information as the basis for commercial negotiations. Pipeline operators are required to publish a range of information, including standing prices, the methodology used to determine these prices, weighted average prices and financial information. This information is designed to reduce the information asymmetry and imbalance in bargaining power shippers can face in negotiations with pipeline operators, facilitating more timely and effective negotiations.

The ACCC has identified some significant problems with the information published by pipeline operators to date, including instances where serious errors have been made and inflationary measures used. The publication of inaccurate information severely undermines the benefits of Part 23 and has the potential to mislead shippers in their negotiations with pipeline operators. The ACCC is disappointed that some pipeline operators do not appear to be taking their responsibilities seriously, given they advocated for the adoption of this lighter handed regulatory approach over changes to the coverage test.

Further, the ACCC has identified a potential limitation in the access request process and a possible weakness in relation of the credibility to the threat of arbitration, which could also undermine the efficacy of Part 23.

To address these issues, the ACCC recommends a range of changes to Part 23, to improve the quality, accessibility and reliability of the reported information and strengthen the negotiation process and threat of arbitration. Some of these improvements will require changes to the AER's Financial Reporting Guideline for Non-Scheme Pipelines, while others will require further consideration through the COAG Energy Council's Gas Pipeline Regulation Reform Regulation Impact Statement (RIS) process, which is reviewing the regulatory framework applying to all gas pipelines. The ACCC also intends to refer the compliance-related matters identified through our review to the Australian Energy Regulator (AER).

Future work of the Inquiry

In keeping with the objectives of the Inquiry, over the last year, the ACCC made a number of recommendations to the Council of Australian Governments Energy Council on how the transparency of the gas market could be improved. These recommendations are set out in:

- a joint report that was prepared with the Gas Market Reform Group (GMRG) entitled, Measures to improve the transparency of the gas market, which was published in December 2018 [12]
- a series of reports published in June 2019, including:
  - *Framework for the consistent reporting of natural gas reserves and resources*[13]
  - *Measures to improve the transparency of wholesale prices in the gas market,*[14] *and*
  - *Adequacy of weighted average pricing information*.[15]

The ACCC understands that these recommendations will be considered as part of a transparency or gas pipeline related regulation impact statement processes that will be conducted by the COAG Energy Council in the latter half of 2019.

The ACCC expects to provide its next interim report in December 2019. In this report, the ACCC will further promote gas price transparency by providing updates on the prices offered and agreed for gas supply across the domestic market. It will also provide updates on the gas supply and demand outlook, C&I gas user experiences and the pricing of transportation services.

12 ACCC, *Framework for the consistent reporting of natural gas reserves and resources*, May 2019, https://www.accc.gov.au/system/files/ACCC-GMRG%20Measures%20to%20Improve%20the%20Transparency%20of%20the%20Gas%20Market.pdf.

13 ACCC, *Measures to improve the transparency of wholesale prices in the gas market*, May 2019, https://www.accc.gov.au/system/files/Framework%20for%20the%20consistent%20reporting%20of%20natural%20gas%20reserves%20and%20resources_0.pdf.

14 ACCC, *Adequacy of weighted average pricing information*, May 2019, https://www.accc.gov.au/system/files/Measures%20to%20improve%20the%20transparency%20of%20wholesale%20prices%20in%20the%20gas%20market_0.pdf.

15 https://www.accc.gov.au/system/files/Adequacy%20of%20weighted%20average%20pricing%20information_0.pdf.

The ACCC will, over the course of the Inquiry, conduct a closer review of:

- the retail gas market to more fully understand the drivers of high margins, including potential barriers to suppliers entering or expanding their operations in retail markets:
    - those users who can only be supplied by retailers, particularly only one retailer, will be a focus for the ACCC
- the ability of shippers to access regional pipelines
- the effect that the capacity trading reforms are having on the demand for transportation services and the behaviour of shippers and pipeline operators, and
- the cost reflectivity of prices charged by pipeline operators.

The ACCC will also:

- continue to publish the LNG netback price series on its website, and
- monitor the effectiveness of the transportation reforms, including the quality of the information reported by pipeline operators and the timeliness and outcomes of negotiations with shippers.

The ACCC will continue to make information available as appropriate and over the course of the inquiry will make further recommendations where it considers it appropriate and necessary to do so.

1. Supply outlook for 2020

1.1. Key points

- Current projections indicate sufficient supply to meet forecast domestic and export demand in 2020.
- The supply outlook for 2020 is better than the supply outlook for 2019 reported in the ACCC's December 2018 report, primarily because:
  - east coast producers expect to produce an additional 113 PJ—increasing overall forecast production from 1875 PJ for 2019 to 1988 PJ for 2020
  - AEMO forecasts gas powered generators (GPG) to consume 16 PJ less—decreasing forecast GPG consumption from 88 PJ for 2019 to 72 PJ for 2020, and
  - LNG producers expect to have an additional 92 PJ of gas available in excess of their contractual commitments—increasing from 76 PJ in 2019 to 168 PJ in 2020.
- The supply forecast provided by gas producers and AEMO's domestic demand forecast indicate that there will be sufficient gas produced in the Southern States to meet demand. However, the supply-demand balance in the Southern States for 2020 remains tight and is subject to:
  - The quantity of gas produced in the south, particularly in the Cooper Basin, that will flow into Queensland. A significant portion of the Cooper Basin production relates to gas acquired by a gas retailer, which contributes to the retailer's east coast portfolio. If the retailer ends up delivering a significant portion of this gas into Queensland, this would significantly tighten the supply-demand balance in the south.
  - Realised demand for gas from 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).
- As at June 2019, the LNG producers have contracted to supply 176 PJ to the domestic market in 2020, which is less than they expect to take out (203 PJ). The 176 PJ represents 33 per cent of expected 2020 domestic demand, compared to the 37 per cent (205 PJ) that the LNG producers had committed to supply in 2019 by the same point last year.
- Gas producers other than the LNG producers expect to produce 568 PJ of gas in 2020.[16] As at the end of April 2019, these producers still had nearly 100 PJ of uncontracted gas, having contracted 469 PJ of gas for supply in 2020.
- The final investment decision on Arrow's Surat Gas Project has been delayed. Arrow aims to make the decision by the end of this year. The ACCC will provide a further update on the progress of the SGP in the December 2019 report.

1.2. Sufficient gas supply is expected in 2020 to meet forecast demand in the East Coast Gas Market

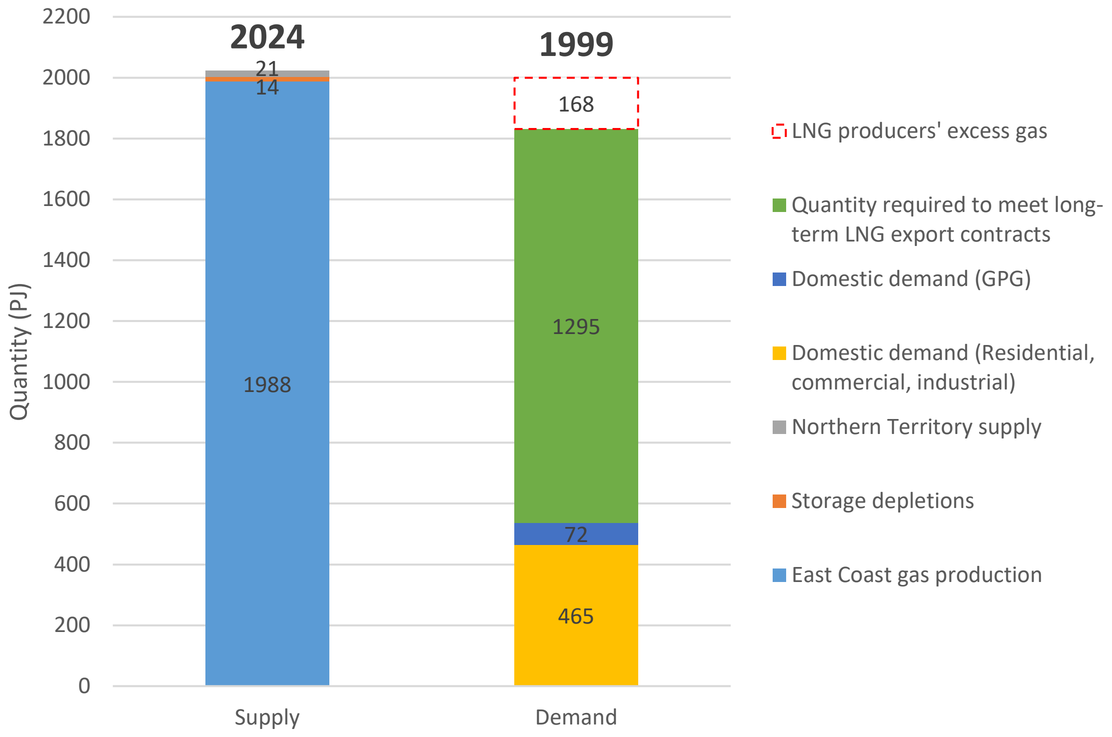
The ACCC previously reported on supply and demand expectations for 2020 in the December 2018 report, as part of an analysis of the long-term supply outlook. Since then, producers have, on aggregate, revised their 2020 production forecasts upward, but the overall supply and demand balance remains about the same.

Chart 1.1 shows the ACCC's current supply and demand outlook for 2020. It shows total forecast supply (production, storage depletions and expected gas flows from the Northern

[16] Includes storage depletions.

Territory to the east coast in 2020) against total forecast demand (AEMO's neutral domestic demand forecast plus the quantities of gas required by the LNG producers to meet their long-term export contractual commitments[17]). The demand forecast includes the quantity of gas that the LNG producers forecast to have available in excess of their contractual commitments for 2020.

Chart 1.1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2020



Source: ACCC analysis of data obtained from gas producers as at June 2019 and of domestic demand data from AEMO's March 2019 GSOO.[18]

Note: Totals may not add up due to rounding.

Current projections indicate sufficient supply to meet domestic and contractual LNG export demand in 2020, although the supply-demand balance will tighten if forecast production is not realised, or if domestic or LNG demand is higher than expected.

The forecast production presented in chart 1.1 only includes production from 2P reserves. While most of this is from well-known, developed areas, about twelve per cent is from less certain, undeveloped areas—that is, projects that may require additional investment before production can commence.

Chart 1.1 does not include production from contingent or undiscovered resources, which are highly uncertain. However, there is currently 19 PJ of gas forecast to be produced from contingent and undiscovered gas resources in 2020, which if realised, would contribute additional quantities of gas to the east coast.

17 Quantities required to meet long-term LNG export contracts are based on the LNG producers' expectations as at June 2019. The quantity actually supplied under these contracts in 2020 may vary due to, for example, flexibility provisions in the contracts, the execution of additional contracts, or unexpected LNG plant maintenance.

18 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2019, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/2019-GSOO-report.pdf. Neutral scenario. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses (17 PJ) with the residential, commercial and industrial category.

The LNG producers expect to have 168 PJ of gas available in excess of their current 2020 contractual commitments, which they can export or sell to the domestic market. In line with their commitment to the Australian Government under the Heads of Agreement, the LNG producers have agreed to first offer this excess gas domestically on competitive market terms before exporting it, even if no shortfall is forecast.[19] This excess gas will likely act as a buffer should a shortfall arise due to higher domestic demand, or lower gas production, than is currently forecast.

The effectiveness of this buffer will depend on whether the LNG projects offer this gas to buyers in the East Coast Gas Market in a way that meets the requirements of buyers. If the gas is offered in large quantities that have to be taken over a short time period, there may not be enough domestic buyers with a capacity to consume, transport and/or store this gas.

Gas producers other than the Queensland LNG producers expect to produce a total of 568 PJ of gas in 2020.[20] As at 24 April 2019, these producers had contracted 469 PJ of gas for supply in 2020, of which 323 PJ was contracted to retailers.[21]

As the ACCC has previously observed, GPG can have a significant impact on the level of domestic gas demand and is highly volatile when compared to other categories of domestic demand (for example, residential and industrial demand).[22] This is because GPG demand 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). This needs to be taken into account when assessing whether forecast supply in 2020 is likely to be sufficient to meet demand expectations.

In AEMO's analysis of the risk factors affecting its forecasts, it rates higher than expected GPG demand as 'possible'. AEMO's analysis states that 'if generation from wind farms or solar generators is lower than expected (within the normal range of annual variability), or [if] 10 per cent of committed renewable generation projects are delayed, GPG demand could be up to 22 PJ higher'.[23] However, the LNG producers appear to have sufficient quantity of excess gas to cover for unexpected fluctuation in GPG demand.

1.3. The LNG producers expect to have sufficient gas to meet their commitments to the domestic and export markets in 2020

Chart 1.2 presents the supply and demand balance of the LNG producers for 2020.

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

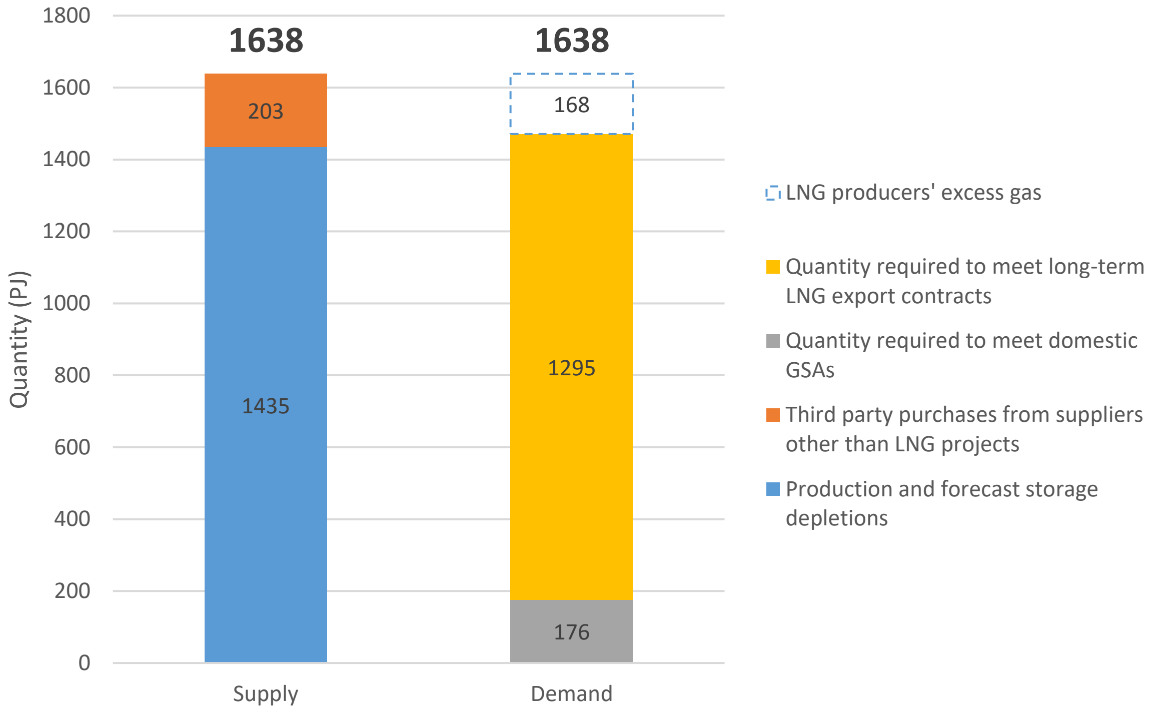
20 Source: ACCC analysis of data obtained from gas producers as at June 2019; includes storage depletions.

21 Source: ACCC analysis of data obtained from gas producers as at April 2019.

22 ACCC, *Gas Inquiry 2017–2020 Interim Report*, September 2017, p. 27; ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2017, p. 23; ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2018, p. 25.

23 Australian Energy Market Operator, Gas Statement of Opportunities, March 2019, p. 9.

Chart 1.2: Forecast supply-demand balance of the Queensland LNG producers for 2020



Source: ACCC analysis of data obtained from the LNG producers as at June 2019.[24]

Note: Totals may not add up due to rounding.

Chart 1.2 shows that the LNG producers are likely to have sufficient gas available to meet their domestic and LNG contractual commitments in 2020.

As noted in section 1.2, the LNG producers expect to have 168 PJ of gas available in excess of their current 2020 contractual commitments, which they can export or sell to the domestic market. This compares with 76 PJ of excess gas for 2019, as reported in the ACCC's December 2018 report. This difference is largely attributable to greater production along with less contracted supply to the domestic market.

The Heads of Agreement between the Australian Government and Queensland LNG producers, signed in September 2018, applies to both 2019 and 2020.[25] The agreement aims to "maintain a secure supply of gas to the east coast domestic market".[26] 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.

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24 Quantities required to meet long-term LNG export contracts are based on the LNG producers' expectations as at June 2019. The quantity actually supplied under these contracts in 2020 may vary due to, for example, flexibility provisions in the contracts, the execution of additional contracts, or unexpected LNG plant maintenance.

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

26 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.

Chart 1.2 shows that the quantity of gas that the LNG producers have thus-far agreed to supply to the domestic market in 2020 (176 PJ) is less than the quantity they expect to take out (203 PJ).[27] In part, this is because we are only part way through 2019 and further contracting for gas is likely to occur over the remainder of this year. Nevertheless, this marks a departure from the prior year. At the equivalent point in time in 2018, the LNG producers had committed 205 PJ to the domestic market for 2019 and were expecting to take out 199 PJ.[28]

While the 176 PJ of gas thus-far committed to the domestic market by the LNG producers for 2020 is lower than the 205 PJ they had committed for 2019 by the same point last year, AEMO's domestic demand estimates for 2020 are also lower than for 2019.[29] This means that the change is less pronounced when viewed in terms of the proportion of expected domestic demand being met by the LNG producers. The 176 PJ committed to the domestic market by the LNG producers for 2020 represents 33 per cent of expected 2020 domestic demand. In comparison, the 205 PJ that the LNG producers had committed by the same point last year for supply in 2019 represented 37 per cent of expected 2019 domestic demand.

This reflects the changing competitive dynamics in the East Coast Gas Market. Non-LNG producers have contracted 380 PJ to domestic buyers for 2020 as at the end of April 2019,[30] which is 45 PJ more than the quantity they had contracted at the same time last year for supply in 2019 (335 PJ).

1.3.1. Greater production, steady long-term export requirements

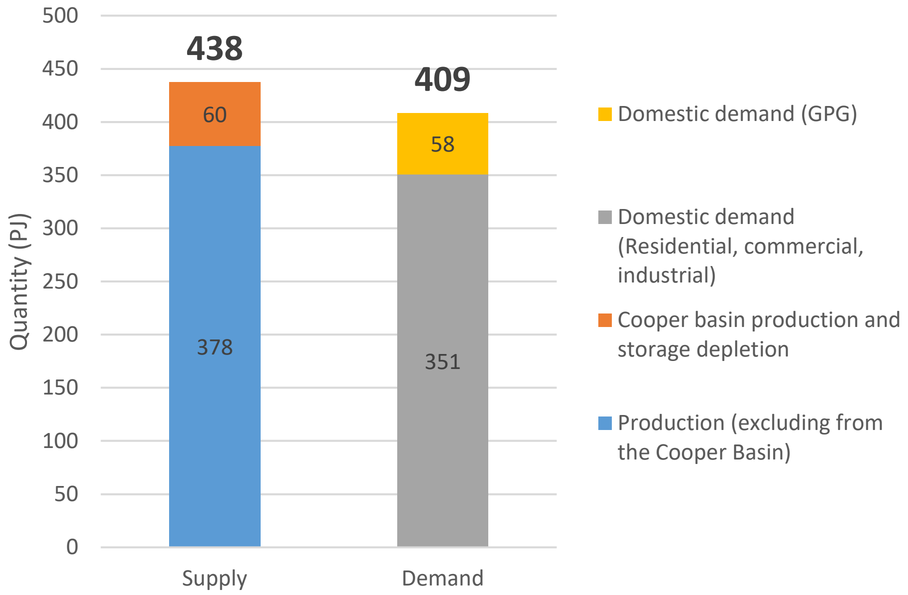
The quantity of gas required by the LNG producers to meet their long-term LNG export contracts in 2020 is only marginally greater (14 PJ) than the quantity required for 2019.[31] In comparison, the LNG producers' expected production for 2020 increased by a greater amount (73 PJ).[32] This has expanded the margin by which the LNG producers' expected production exceeds their long-term export contract requirements to 140 PJ for 2020, up from 81 PJ for 2019.[33]

1.4. The supply-demand balance in the Southern States remains tight

Chart 1.3 presents the supply and demand balance for the Southern States for 2020. The production forecast in the chart includes production in offshore Victoria, Camden (NSW) and a proportion of gas from the Cooper Basin.

27 As at June 2019.
28 ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2018, p. 26.
29 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2019.
30 That is, buyers other than the LNG producers.
31 Quantity for 2019 as reported in the ACCC's December 2018 report.
32 Ibid; includes storage depletions.
33 Production includes storage depletions.

Chart 1.3: Forecast domestic supply-demand balance in the Southern States for 2020 (including a proportion of Cooper Basin gas)



Source: ACCC analysis of data obtained from gas producers as at June 2019 and of domestic demand data from AEMO's March 2019 GSOO.[34]

Note: Totals may not add up due to rounding.

Current projections indicate sufficient supply to meet demand in the Southern States in 2020. However, the overall balance remains tight and similar to the balance for 2019 that we reported in the December 2018 report, with a small decrease on the supply side matched by an equivalent reduction on the demand side.

The reduction on the demand side is attributable to AEMO's forecasts for GPG demand. AEMO's most recent demand forecasts show an expected reduction in GPG demand in the Southern States from 74 PJ in 2019 to 58 PJ in 2020. In comparison, AEMO expect the residential, commercial and industrial component of domestic demand to remain steady.[35]

As discussed in section 1.2, GPG demand is dependent on factors that are difficult to forecast accurately. This is reflected in AEMO's analysis of the risk factors affecting its forecasts, in which it rates higher than expected GPG demand as 'possible'. AEMO cites potential risk factors including lower than expected wind or solar generation, delays to renewable generation projects, and unexpected unavailability of coal-fired generation.[36] Higher than expected GPG demand in 2020 would tighten the supply and demand balance in the Southern States.

AEMO's forecast decline in Southern States GPG demand reflects its expectation that a declining trend will continue through 2019 and 2020, following actual GPG usage in the Southern States of 137 PJ in 2017 and 96 PJ in 2018. AEMO attributes this declining trend to increased penetration of renewable generation, but expects GPG demand to stabilise in the medium-term and grow slightly in the long-term, reflecting the role that GPG plays in providing reliability and security to complement renewable generation.[37]

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34 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2019, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/2019-GSOO-report.pdf. Neutral scenario. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses (14 PJ) with the residential, commercial and industrial category.

35 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2019.

36 Ibid, p. 9.

37 Ibid, pp. 4–5.

On the supply side, there is an increase in expected production in 2020 in the Gippsland Basin, compared to the production estimates for 2019 that we reported in the December 2018 report, including from Cooper Energy's Sole project and the Gippsland Basin Joint Venture (GBJV). However, less Cooper Basin gas is currently expected to flow to the Southern States.

Esso Australia, the operator of the GBJV, explained that its West Barracouta project is the main driver of expected increases in production from the GBJV across both 2019 and 2020, along with flow-on resource assessments enabling accelerated gas production from the legacy Snapper and Barracouta fields. As reported in section 1.8, GBJV partners Esso and BHP approved investment in the West Barracouta project in December 2018. Despite the increase, forecast production by the GBJV in 2020 remains significantly lower than its 2017 peak (322 PJ) due to reduced production from its depleting legacy fields.[38]

A portion of the Cooper Basin gas that the ACCC has included in the supply forecast for the Southern States relates to gas acquired by a gas retailer. The gas contributes to the retailer's overall portfolio. Where the retailer will deliver this gas in 2020 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.

Another 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 2020. As previously reported by the ACCC, the bulk of Cooper Basin production is contractually committed to the LNG producers in Queensland. However, for 2020, some of this gas has been swapped out to supply the Southern States.[39] While the Cooper Basin is expected to contribute these additional quantities to the Southern States in 2020, this may not be the case in future years.

1.5. Queensland is likely to have sufficient gas to meet its needs in 2020

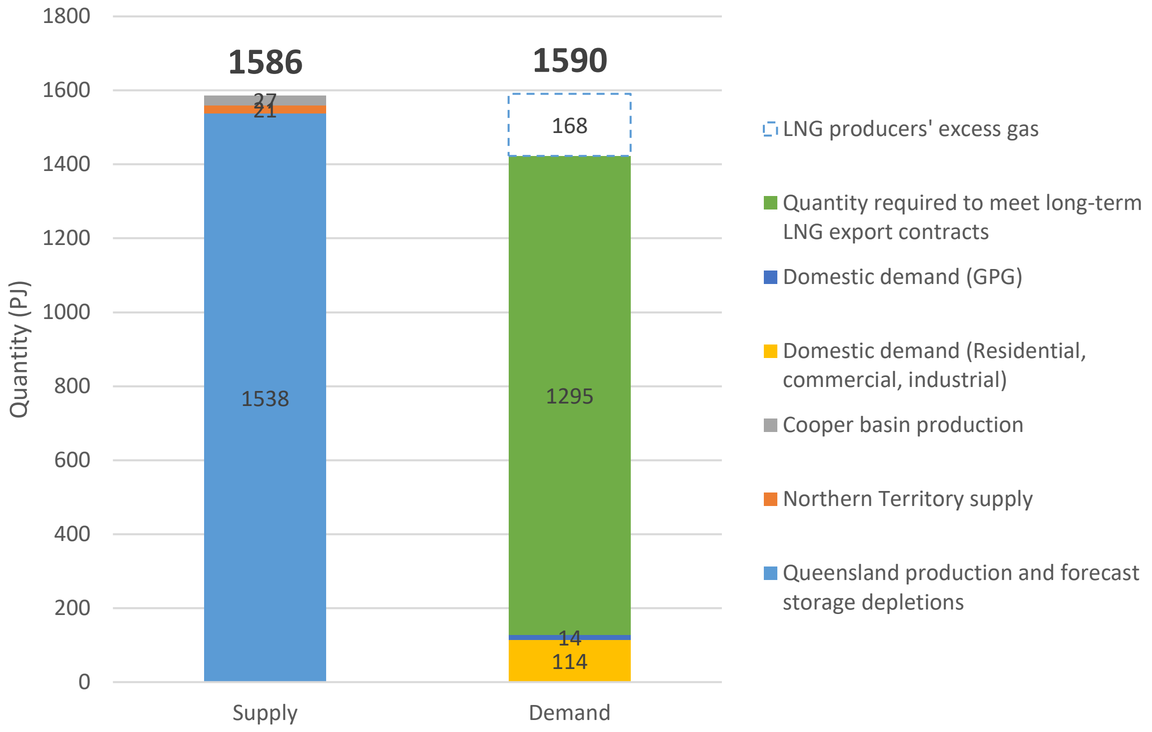
Chart 1.4 presents the supply and demand balance for Queensland for 2020.[40]

[38] ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2018, p. 29.

[39] ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2018, p. 31; ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2018, p. 28.

[40] Forecast supply is comprised of Queensland's total production plus forecast storage depletions; expected supply from the Northern Territory; and a proportion of gas from the Cooper Basin that is currently expected to flow into Queensland. Forecast demand is comprised of AEMO's neutral domestic demand forecast for Queensland plus the quantities of gas required by the LNG producers to meet their long-term export contractual commitments.

Chart 1.4: Forecast supply-demand balance in Queensland for 2020



Source: ACCC analysis of data obtained from gas producers and LNG producers as at June 2019, and of domestic demand data from AEMO's March 2019 GSOO.[41]

Note: Totals may not add up due to rounding.

Chart 1.4 shows that there is sufficient production in Queensland to meet both domestic and contracted LNG export demand in 2020, even in the absence of gas from the Cooper Basin or the Northern Territory. However, Queensland's supply-demand balance will tighten if the majority of the LNG producers' excess gas is used to supply export markets.

Based on current firm gas supply commitments, 21 PJ of gas is forecast to flow into Queensland from the Northern Territory in 2020. As the Northern Gas Pipeline'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. Queensland gas tenements with domestic supply conditions

Over the past two years, the Queensland government has issued tenements with domestic supply conditions to six gas producers[42]: Senex Energy, Chi Oil and Gas, Armour Energy, Central Petroleum, a joint venture between Santos and Shell, and a joint venture between APLNG and Armour Energy[43]. Gas produced from each of these tenements must be sold domestically, and gas from the APLNG/Armour Energy tenement has an additional requirement that it must be sold to a manufacturer. At the 2018 Australian Domestic Gas Outlook conference in Sydney, Queensland Minister for Natural Resources, Mines and

41 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2019, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/2019-GSOO-report.pdf. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses (2 PJ) with the residential, commercial and industrial category.

42 Chinchilla News and Murilla Advertiser, '*More Queensland gas fuels manufacturing jobs*', 7 June 2019, https://www.chinchillanews.com.au/news/more-queensland-gas-fuels-manufacturing-jobs/3748077/.

43 Queensland Government, '*Industrial jobs and $106 million investment secured at Incitec Pivot*', 4 June 2019, http://statements.qld.gov.au/Statement/2019/6/4/industrial-jobs-and-106-million-investment-secured-at-incitec-pivot.

Energy, Dr Anthony Lynham, said that ‘these releases are shoring up Australia’s gas supply—further demonstrating Queensland as a reliable and affordable gas producer’.[44]

The six tenements are currently at different stages of development, and some of the producers have begun marketing gas. It has been widely reported that APLNG entered into a GSA with Incitec Pivot, to supply Incitec’s Gibson Island fertiliser plant until at least the end of 2022.[45] The deal has reportedly secured around 450 jobs at the Gibson Island plant. The first gas from the tenement is expected in mid-2020. Senex Energy has also announced three GSAs for gas from its domestic supply tenement, Project Atlas. These are with C&I users CSR Building Products,[46] Orora[47] and O-I Australia.[48] Supply to CSR and Orora will commence in January 2020, and to O-I Australia in January 2021. As noted in section 5.2, Senex has also signed an agreement with Jemena for the latter to develop the Atlas Gas Processing Plant and Pipeline to connect the Atlas gas field to the East Coast Gas Market.[49]

As most of the tenements with domestic supply conditions are still in their early stages of development, it is too early to comment on the impact the release of tenements with domestic only conditions will have on supply-demand dynamics, the state of competition and prices achieved by producers for gas from these tenements.

Broadly, release of these tenements is a good development for the gas market, as it allows additional gas to be produced that has value to the economy in excess of its cost of production. Whether this additional gas will result in more gas being supplied into the domestic market overall depends on the extent to which this gas displaces supply into the domestic market from other sources. For example, the production of gas from these tenements will have no impact on the overall domestic supply-demand balance in the east coast, if an equivalent quantity of gas from other sources in the east coast, which would have been otherwise supplied into the domestic market, is exported instead.

Further, conditions placed on the tenements may benefit some buyers negotiating with the producers of these tenements. To the extent that conditions limit the alternatives available to the producers when selling gas, these conditions increase the bargaining power of the buyers and can be expected to place downward pressure on the price that the buyer may be able to achieve in negotiations with the producer.

For example, a tenement issued with a condition that limits producers to selling gas only to domestic manufacturers effectively precludes those producers from selling gas to either an LNG producer or a portfolio player (e.g. retailer). In 2018, producers in the east coast sold around 80 per cent of their gas to retailers or LNG producers. A condition that effectively removes the option of selling gas to such a significant portion of demand is likely to improve the bargaining power of a manufacturer negotiating with the producer for supply of gas from that tenement.

However, to the extent that such conditions confer any pricing benefits, those are likely to be limited to the individual buyers negotiating with the producers of those tenements and may not flow through to the broader market.

44 Queensland Department of Natural Resources, Mines and Energy, ‘*Qld opens more land to meet domestic gas supply challenge’*, March 2018, https://www.dnrme.qld.gov.au/home/news-publications/news/2018/march/qld-opens-more-land-to-meet-domestic-gas-supply-challenge.

45 The Sydney Morning Herald, ‘*Gibson Island fertiliser plant to stay open, saving 450 jobs’*, 4 June 2019, https://www.smh.com.au/business/companies/gibson-island-fertiliser-plant-to-stay-open-saving-450-jobs-20190604-p51u92.html.

46 ASX Announcement—Senex Energy Limited, ‘*Senex agrees domestic gas supply contract with CSR’*, 17 April 2019, https://www.senexenergy.com.au/wp-content/uploads/2019/04/1921018.pdf.

47 ASX Announcement—Senex Energy Limited, ‘*Senex and Orora agree domestic gas supply contract*, 1 May 2019, https://www.senexenergy.com.au/wp-content/uploads/2019/05/Senex-and-Orora-agree-domestic-gas-supply-contract.pdf.

48 ASX Announcement—Senex Energy Limited, ‘*Senex and O-I Australia agree domestic gas supply contract*, 11 June 2019, https://www.senexenergy.com.au/wp-content/uploads/2019/06/1937310.pdf.

49 Jemena, *Jemena and Senex partner to fast-track new gas supply to market (Media Release)*, 18 June 2018.

Further, care needs to be taken in designing tenement conditions and issuing the tenements to minimise the likelihood of unintended consequences. For example, there are several benefits for a producer in selling gas to a retailer or LNG producer. These buyers can take large quantities and can enter into flexible arrangements, ensuring a reliable revenue stream for the producer. Further, it may be difficult for producers to sell gas to C&I gas users that are located in regions in which the producer does not have pipeline capacity. Restricting sellers to only supplying domestic manufacturers could increase the risk associated with the development and marketing of gas from these tenements. This could subsequently limit the range of producers that are likely to bid for, and/or win, those tenements to majors, squeezing out smaller producers, which are important for diversity of supply and the level of competition in the market.

1.7. Arrow's Surat Gas Project

Arrow Energy Holdings Pty Ltd is a standalone company owned by Shell and PetroChina (50/50) (the shareholders). Arrow holds significant undeveloped 2P gas reserves in the Surat Basin.[50] In December 2017, Arrow announced that it had executed a GSA with the QCLNG joint venture, which Arrow said would commercialise the majority of those reserves.[51] However, Arrow's shareholders are yet to reach a final investment decision (FID) on the project, known as the Surat Gas Project (SGP).

The ACCC sought an update from Arrow on the progress of the SGP and reviewed Arrow's Board documents.

Arrow has explained that SGP is a large and complex project. Progression of the shareholders' approvals for an SGP FID was delayed because of a six months delay in receiving confirmation of a third party consent required in relation to securing access to key third party infrastructure. Arrow and the shareholders have resumed discussions regarding the technical parameters and development plan for the SGP.

Arrow explained that it is expected that Arrow and the shareholders will need to update and reassess a number of economic and non-technical factors relevant for an FID.

Arrow is aiming for an FID to be made before the end of 2019. The ACCC will provide a further update on the progress of the SGP in our December 2019 report.

1.8. Recent market developments

There have been a number of developments since the ACCC's April 2019 report that could result in additional supply being brought to the domestic market.

1.8.1. Santos' Narrabri Gas Project remains uncertain despite signing customers

In June 2019 the Australian Financial Review reported that 'state and federal government sources have told *The Australian Financial Review* that [Santos' Narrabri] project, which has been subject to an unofficial state moratorium on coal seam gas for several years, should get the green light by Christmas'. The article also reported that Santos has stated that it will sell all of the gas produced to domestic customers.[52]

However, the NSW Planning and Public Spaces Minister has downplayed speculation of the project's imminent approval, telling the Sydney Morning Herald that there are 'robust and thorough processes for major projects which have significant implications for the state, its

50 Arrow Energy, Arrow Energy agrees deal for Surat Basin reserves (Media Release); see also, ACCC, Gas Inquiry 2017–2020 Interim Report, December 2018, p. 46.
51 Ibid.
52 Australian Financial Review, Controversial CSG project set to get green light, 21 June 2019.

people and its resources'.[53] It is uncertain whether the NSW Government's approval of the Australian Industrial Energy's (AIE) LNG import terminal will influence the likelihood of approval for the Narrabri Gas Project.

Santos has recently signed memoranda of understanding to supply Narrabri gas to C&I users Brickworks and Perdaman Group, as well as gas wholesaler Weston Energy. Subject to the project's approval, Santos would supply Brickworks with up to 3 PJ of Narrabri gas per year for seven years, and Weston with 10 PJ per year for ten years.[54]

1.8.2. AIE (Port Kembla) is the first LNG import terminal to attain planning approval

The ACCC's April 2019 report noted that a total of five proposals for LNG import terminals were on foot on the east coast, but none had yet been sanctioned.[55] The New South Wales government has since granted the necessary planning approval to AIE's Port Kembla LNG import terminal project.[56] While AIE has yet to announce a final investment decision, it has signed a deal for EnergyAustralia to take 15 PJ of imported gas per year for five years starting in 2021, subject to the project's approval.[57]

AGL has announced that a final investment decision on its proposed Crib Point LNG import project has been delayed until at least late in the 2019–2020 financial year. Under this new timeline, AGL expects first gas from the project to be delivered in the second half of the 2021–2022 financial year.[58] AGL had previously stated that it was working toward a final investment decision in the 2018-2019 financial year that would see first gas delivered during the 2020–2021 financial year.[59]

1.8.3. Northern Territory government approves fracking in the Beetaloo basin

The Northern Territory Government has lifted its moratorium on fracking in the Beetaloo Basin, approving plans by Origin and Santos to resume works at their respective projects in the area.[60] Meanwhile, the 2019 Federal Budget included $8.4 million 'to support feasibility studies to accelerate gas supplies from the Northern Territory to the east coast market by opening the Beetaloo Sub-basin for exploration and development'.[61]

Origin states that the Beetaloo Basin 'has the potential to be a game-changer for the Australian gas industry', noting that two more wells will be drilled in 2019 to provide a better indication of the viability of the gas resource.[62] In July 2017, the Australian Financial Review reported that Citigroup estimates Origin's Beetaloo permits may yield more than 100 trillion cubic feet of gas.[63]

1.8.4. Victorian onshore gas study

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53 Sydney Morning Herald, Santos coal seam gas plan still has hurdles to clear: NSW government, 22 June 2019.

54 Santos, Santos signs MOUs with Brickworks and Weston Energy for Narrabri gas (Media Release), 9 May 2019: https://www.santos.com/media-centre/announcements/santos-signs-mous-with-brickworks-and-weston-energy-for-narrabri-gas/.

55 ACCC, Gas Inquiry 2017-2020 Interim Report, April 2019, p. 11.

56 Sydney Morning Herald, Port Kembla gas terminal gets planning go-ahead, 29 April 2019.

57 Australian Financial Review, The Forrest gas train really is rolling now, 24 May 2019.

58 AGL, Update on Crib Point gas import project (Media Release), 28 June 2019: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/june/update-on-crib-point-gas-import-project.

59 AGL, AGL reaches key milestones for proposed LNG import jetty (Media Release) 12 June 2018: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2018/june/agl-reaches-key-milestones-for-proposed-lng-import-jetty.

60 ABC (online), Fracking exploration in NT to begin in 'coming days, if not weeks', 12 June 2019.

61 Department of Treasury, Budget Paper No. 2: Budget Measures 2019–20, p. 78.

62 Origin Energy, Getting back on the ground in the Beetaloo (Media Release), 6 September 2018: https://www.originenergy.com.au/blog/big-picture/getting-back-on-the-ground-in-the-beetaloo.html.

63 Australian Financial Review, *Origin Energy sizes up Beetaloo gas prize*, 20 July 2017.

The Victorian government has announced that it will undertake studies of onshore conventional gas reserves in Victoria ahead of the June 2020 end of the current exploration and development moratorium. The studies will 'provide an evidence-based estimate of prospective gas resources and look closely at the risks, benefits and impacts associated with onshore conventional gas to inform future decisions of Government.' [64]

The ACCC has called for state governments, in the Southern States in particular, to adopt policies that consider and manage the risks of individual gas development projects, rather than implementing blanket moratoria and regulatory restrictions.[65]

1.8.5. Origin Energy's sale of Ironbark and Heytesbury assets

Origin has sold its Ironbark coal seam gas project to APLNG, with the ACCC deciding not to oppose the acquisition.[66] This follows Origin's 2018 write-down of the Ironbark reserves by almost half.[67] Origin has also sold its depleted Heytesbury gas reservoir assets in Victoria to Lochard Energy, which also owns the nearby Iona gas storage facility.[68]

1.8.6. GBJV West Barracouta project

In December 2018, the Gippsland Basin Joint Venture parties BHP and Esso announced that they had approved investment in the development of the western dome of the Barracouta gas field (known as the West Barracouta project). BHP and Esso will together invest around $550 million to bring the 128 billion cubic feet of wet gas to market, with first gas expected in 2021.[69]

1.8.7. BHP and Esso begin separately marketing GBJV gas

From 1 January 2019, BHP and Esso began separately marketing their respective shares of gas produced under the GBJV. BHP and Esso had committed to separate marketing from 1 January 2019 in a court enforceable undertaking provided to the ACCC in December 2017, following an ACCC investigation into the effect of joint marketing arrangements between the two parties for GBJV gas.[70]

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64 Victorian Department of Jobs, Precincts and Regions, *Victorian Gas Program*: https://earthresources.vic.gov.au/projects/victorian-gas-program.

65 ACCC, *East coast gas prices need to follow export prices down* (Media Release), 30 May 2019: https://www.accc.gov.au/media-release/east-coast-gas-prices-need-to-follow-export-prices-down.

66 ACCC, *APLNG's acquisition of Origin's Ironbark project not opposed* (Media Release), 22 May 2019: https://www.accc.gov.au/media-release/aplng%E2%80%99s-acquisition-of-origin%E2%80%99s-ironbark-project-not-opposed.

67 ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2018, p. 52.

68 Australian Financial Review, *Origin Energy, QIC's Lochard sign storage assets deal*, 4 February 2019.

69 Australian Financial Review, *Esso-BHP to boost east coast gas with $550m Bass Strait project*, 13 December 2018.

70 ACCC, *BHP and Esso to separately market Gippsland Basin gas* (Media Release), 18 December 2017.

1.8.8. Gas pipeline capacity trading

In mid-2018, the Council of Australian Governments (COAG) Energy Council agreed to implement a range of measures to facilitate more capacity trading on key transmission pipelines and compression facilities and, in so doing, improve the efficiency with which this capacity is allocated and used. The measures provided for, amongst other things, the development of a capacity trading platform (that would form part of the Gas Supply Hub) and a day ahead auction of contracted but un-nominated capacity. These two market mechanisms, which are operated by AEMO, commenced operation on 1 March 2019.

In the first four months of operation there have been no trades conducted through the capacity trading platform. The auction, on the other hand, has been used by a small number of shippers to procure between 10 and 151 TJ/day of capacity (average 77 TJ/day) in its first four months of operation, with most trades clearing at the auction reserve price of $0/GJ.[71] Over this period the auction has been used to transport around:

- 1.5 PJ of gas on the RBP
- 2.4 PJ of gas on the SWQP
- 3.6 PJ of gas on the MSP, and
- 0.17 PJ of gas on the EGP.

In addition to facilitating the movement of more gas across the East Coast Gas Market, the ACCC understands that the auction has facilitated additional gas trades through the Moomba GSH.

Further detail on the amount of capacity procured through the auction can be found on the Bulletin Board and in the AER's gas market performance reports.

[71] AER, *Gas Market Report*: 19–25 May 2019, p. 4.

2. Domestic price outlook for 2020

2.1. Key points

- In the first quarter of 2019, gas producers made offers for 2020 supply at prices mostly below $10/GJ, while retailers have largely continued to make offers to C&I gas users at $10-12/GJ.[72]
- After reaching a peak of almost $11/GJ in October 2018, expected 2020 LNG netback prices at Wallumbilla fell to below $9/GJ by the middle of April and just over $8/GJ by the end of June.
- In the first quarter of 2019, the averages of prices offered by producers in Queensland for gas supply in 2020 have fallen broadly in line with expected 2020 LNG netback prices. The averages of prices offered by retailers in the Southern States appear quite high relative to the expected LNG netback prices and may be reflective of the tight supply-demand balance in the Southern States (discussed in Chapter 1).
- The average of prices for 2020 expected to be paid under GSAs entered into between 1 January 2018 and the end of April 2019, are:
  - $8.99/GJ by all buyers[73] to Queensland producers
  - $9.72/GJ by all buyers to producers in the Southern States
  - $10.33/GJ by C&I gas users to retailers in Queensland
  - $10.74/GJ by C&I gas users to retailers in the Southern States.
- The time series of GSAs executed in each half year interval from the second half of 2016 to the end of 2018 shows that the average of prices agreed by C&I gas users under GSAs jumped by over $2/GJ between the second half of 2016 and the second half of 2017 and remained within $9–10/GJ range until the end of 2018.[74]
- The ACCC engaged Platts to prepare a report on delivered gas prices paid by C&I gas users in a range of countries around the world. The report shows that the delivered prices that C&I gas users in the East Coast Gas Market pay are:
  - lower than the delivered prices paid by C&I gas users in Asian countries that purchase Australian LNG (e.g. South Korea and China)—this is to be expected given the costs involved in delivering Australian's gas to those countries, and
  - higher than the delivered prices paid by C&I gas users in other gas exporting countries (e.g. US and Canada)—this reflects the unique characteristics of the East Coast Gas Market, particularly high gas production costs, high transmission prices and close linkage to the international LNG markets.
- Average load factor and take or pay levels demonstrate that many gas buyers in the east coast are accepting limited flexibility in their GSAs with both producers and retailers.
- Liquidity in the futures markets linked to the Declared Wholesale Gas Market continues to grow, with trading over the first 5 months of 2019 well above that seen over the same period in 2018.

2.2. Introduction

This chapter presents information about wholesale gas prices in the East Coast Gas Market. Box 2.1 sets out the key parameters relevant to the analysis in this chapter.

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72 Unless otherwise specified, all references to 'prices' in this chapter are references to gas commodity prices, which do not include separate transportation or other ancillary charges.

73 The term 'buyers' includes retailers as well as end users of gas.

74 Some of the GSAs executed in 2019 are for supply commencing in 2021.

Box 2.1: Parameters of reported prices

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

- The prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges. The prices charged for transportation have been excluded from the analysis to enable a more direct comparison between the prices paid by buyers with differing transportation requirements.
- Only arm's length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Only those transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included.
- Where average prices are reported, these are quantity-weighted average prices.
- The following entities were classified as 'retailers': Origin Energy, AGL, EnergyAustralia, Alinta Energy, Shell Energy Australia and Macquarie Bank (refer to Glossary for further details).
- 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.

Gas suppliers in the Northern Territory have commenced supplying gas into the East Coast Gas Market via the Northern Gas Pipeline (NGP). However, 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.

2.3. Prices offered for gas supply in 2020

This report marks the second time we have reported on offers made and bids received by suppliers in the East Coast Gas Market for gas supply in 2020. We extend our previous coverage with the addition of information on offers made and bids received by gas suppliers between 24 January 2019 and 23 April 2019.

Box 2.2 below sets out the ACCC's approach to reporting on offers and bids.

Box 2.2: Approach to reporting on offers and bids

The information in this box should be read in conjunction with information in box 2.1. The following also applies to the analysis of offers and bids in this section:

- The analysis only includes those offers and bids that are sufficiently developed to contain clear indications of price, quantity, supply start and end dates.
- The gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil prices, foreign exchange rates and the consumer price index) based on the expectations for those variables at the time of the offer or bid.[75]
- Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  - For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2020) by taking a simple average of Brent crude oil prices expected in each month of that year.
  - We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  - We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.

Analysis of offer and bid pricing throughout this chapter is intended to provide an indication of price trends over time. As explained in box 2.1, 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 gas powered electricity generation (GPG), conditions in the electricity market.

While construction of the NGP has created scope for Northern Territory producers to begin making offers to, and receiving bids from, buyers in the East Coast Gas Market, these have been excluded from the offers and bids analysis unless the delivery point is in the east coast. In the period between 24 April 2018 and 24 April 2019, Northern Territory producers made a small number of offers and received a small number of bids at lower commodity gas prices compared to those reported in table 2.1. However, once the cost of transportation from the Northern Territory is included, the offers from and bids to the Northern Territory producers are broadly consistent with the prices of offers made and bids received by east coast suppliers, as reported in table 2.1.

Since September 2017, the Queensland government has awarded a number of tenements to gas suppliers that have domestic supply conditions, including one tenement with a condition to supply domestic manufacturers only. Section 2.2 below discusses the impact that these conditions may have on prices received by the gas producers. For the purpose of the analysis in this report, the ACCC has excluded offers and bids for gas that can only be supplied to domestic manufacturers, as the prices observed in these offers and bids may not

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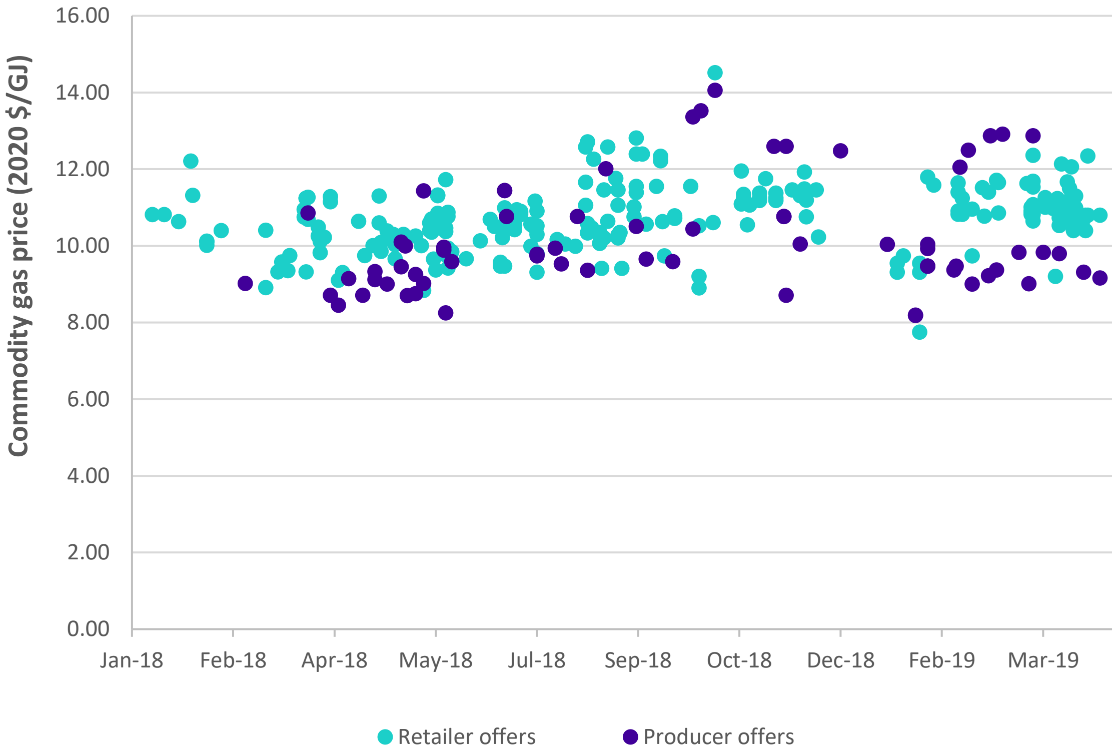
75 In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:
- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA).
- The expected Brent crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japanese Customs Cleared (JCC) crude oil price is derived using the expected Brent crude oil price as a proxy.
- The expected Japan Korea Marker (JKM) LNG price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5 per cent thereafter.

be comparable to other prices in the East Coast given the limited number of potential purchasers of this gas. Based on the offers observed by the ACCC so far, these appear to be towards the lower end of the range presented below. The ACCC has included offers and bids for gas that will be supplied from tenements with more generic domestic supply conditions.

2.3.1. Offers and bids for gas supply in 2020

Chart 2.1 below shows the gas commodity prices included in offers made by producers and retailers for supply in 2020 over the period from 1 January 2018 to 24 April 2019. Not all price offers in the chart (and those discussed in this section) are for unique combinations of seller and buyer, and some offers may reflect follow up offers that were made from 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 for gas supply in 2020 has evolved since January 2018.

Chart 2.1: Gas commodity prices offered for 2020 supply in the East Coast Gas Market



Source: ACCC analysis of offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ and a term of at least 12 months.

Chart 2.1 shows that while there is a somewhat similar trend in prices charged by producers and retailers throughout 2018, there is a clear divergence in the prices charged by producers and retailers in the early part of 2019.

In the first half of 2018, prices offered by producers were largely concentrated in the $8/GJ to $10/GJ range. Producer prices increased in the second half of 2018, with the bulk of the offers above $10/GJ. From January 2019, prices largely fell back to the $9/GJ to $10/GJ range.

All the producer offers above $12/GJ shown in the chart have pricing mechanisms linked to Brent crude oil prices, and were made when oil prices were relatively high, leading to the high offer prices shown (refer to box 2.2 for explanation of how we calculated indicative gas prices for oil-linked offers).

Retailer offers were mostly between $9/GJ and $11/GJ in the first half of 2018. Retailer offers increased in the second half of 2018, with the bulk of the offers between $10/GJ and $12/GJ. Some of the retailer offers were above $12/GJ and one offer was above $14/GJ. While there were fewer offers above $12/GJ in the early part of 2019, the bulk of the retailer offers have remained in the range between $10/GJ and $12/GJ.

The chart shows that while many of the retailer offers throughout 2018 were competitive with the producer offers, there is a clear divergence between retailer and producer offers in the early part of 2019. The bulk of the retailer offers are well above the producer offers (excluding the oil-linked producer offers).

Table 2.1 presents analysis of recent offers made and bids received by gas producers for gas supply to all buyers in 2020. The table compares the offers made and bids received in the periods from 1 January 2018 to 23 January 2019 (period 1) and from 24 January 2019 to 24 April 2019 (period 2).[76] Period 1, the period for which we reported on bids and offers in the April 2019 interim report, is slightly longer than a year. This means it should account for seasonality throughout the year, as opposed to period 2 which accounts for the most recent three months for which we have data.

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

Period 1: 1 January 2018 to 23 January 2019	**Offers**	**Bids**
Number of offers or bids	48	76
Gas commodity price range ($/GJ)	8.18–14.05	6.29–11.30
Quantity weighted average gas commodity price ($/GJ)	10.46	9.06

Period 2: 24 January 2019 to 24 April 2019	**Offers**	**Bids**
Number of offers or bids	21	46
Gas commodity price range ($/GJ)	9.00–12.91	8.00–12.59
Quantity weighted average gas commodity price ($/GJ)	10.44	9.54

Source (period 1): ACCC, Gas Inquiry 2017–2020 Interim Report, April 2019, table 2.3, and additional information received after the publication of that report.

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

Table 2.1 shows that the average of prices offered by producers in period 2 (91 days) was $0.02/GJ lower than in period 1 (389 days), while the average bid price in period 2 was $0.48/GJ higher than in period 1. This indicates that, on average, offer and bid prices have converged slightly.

[76] Period 1 covers 'recent offers and bids' we reported in the April 2019 interim report, while period 2 covers offers and bids we have received since.

Offers made by producers in period 2 for gas supply in 2020 were on average $0.90/GJ more expensive than the bids received by producers. This is to be expected given that offers (made by suppliers) are typically priced higher than bids (made by buyers).

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

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

Period 1: 1 January 2018 to 23 January 2019	Offers	Bids
Number of offers or bids	159	11
Gas commodity price range ($/GJ)	8.83–14.52	6.80–12.40
Quantity weighted average gas commodity price ($/GJ)	10.63	8.87

Period 2: 24 January 2019 to 24 April 2019	Offers	Bids
Number of offers or bids	73	<5
Gas commodity price range ($/GJ)	7.75–12.36	7.08–10.82
Quantity weighted average gas commodity price ($/GJ)	11.07	10.01

Source (period 1): ACCC, *Gas Inquiry 2017–2020 Interim Report*, April 2019, table 2.4.

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

Table 2.2 shows that both offers made by retailers and bids received by retailers from C&I gas users in period 2 were on average more expensive than in period 1. Offers were $0.44/GJ more expensive in period 2, whereas bids were $1.14/GJ more expensive (largely due to some more expensive, high quantity bids holding the quantity weighted average up). Offers made by retailers in period 2 were on average $1.06 more expensive than bids received by retailers, which is a similar differential to producer offers and bids.

The spreads of retailer offer and bid prices were narrower in period 2 than they were in period 1, due to period 1 accounting for a far greater time period.

2.4. Prices offered for gas supply in 2020 compared to contemporaneous LNG netback price expectations and production costs

This section compares prices offered for 2020 supply in the East Coast Gas Market in each month between January 2018 and April 2019 with:

- expectations of 2020 LNG netback prices at the time the offer was made, based on market expectations (at the time the offer was made) of Asian LNG spot prices over the course of 2020 (box 2.3) [77]
- the estimated cost of gas production, which is based on the estimated breakeven gas price of the marginal supplier of gas, in the relevant region, for 2020 (box 2.4).

In previous reports, the ACCC compared all offers made by producers and retailers with LNG netback price expectations. The vast majority of these offers related to gas supply contracts with a term between 1–3 years. Over the first half of 2019, however, there has been a substantial increase in the number of offers that relate to contracts with a term greater than 3 years, with some of these extending beyond 5 years.

Information obtained by the ACCC from suppliers in the east coast indicates that suppliers are unlikely to use expected future LNG spot prices to assess prices in domestic contracts with a term beyond 3 years. In part, this is due to the volatility in Asian LNG markets (see section 2.4.1 below), and the fact that LNG spot futures markets have little to no liquidity beyond a few years into the future.

On this basis, the ACCC has included in the analysis in this section only those offers that relate to contracts with a term between 1-3 years.

This report marks the first time that the ACCC has compared offers for supply in 2020 with LNG netback prices.

Box 2.3: LNG netback prices used for comparison

The ACCC has used LNG netback prices based on Asian LNG spot prices to compare against prices offered in the East Coast Gas Market, as Asian LNG spot prices are a key factor influencing domestic gas prices under current market conditions (given LNG markets offer an alternative to selling gas in the domestic market). To calculate an LNG netback price to compare against offers for future supply, we have:

- calculated a forward-looking LNG netback price as at the date of the offer—based on market expectations of future LNG spot prices during the period of supply—as this gives the best indication of the likely opportunity cost of supplying gas to the domestic market[78]
- used short-run marginal costs of LNG production and transport, since LNG producers are making decisions about the sale of excess gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC's website, and which are outlined in the ACCC's Guide to the LNG netback price series.[79]

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77 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.

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

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

The domestic offers analysed in this section are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison, we calculated an average LNG netback price that an LNG exporter would expect to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2020, and selling cargoes on the Asian LNG spot market in 2020.

For example, the ACCC calculated the average of LNG netback prices for 2020 that an LNG producer would have expected in July 2018 as follows:

- The ACCC obtained JKM futures prices for each month of 2020 that were quoted by ICE on each day during July 2018.
- The ACCC converted the monthly 2020 JKM futures prices into LNG netback prices at Wallumbilla by:
    - converting the prices from US$/MMBtu into A$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ, and
    - subtracting the short-run marginal costs of shipping, liquefaction[80] and transportation.[81]
- The ACCC averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2020 expected on each day during July 2018.
- The ACCC then averaged these 2020 expectations for each day of July 2018 to arrive at an average of LNG netback prices for 2020 expected during the month of July 2018.

[80] 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.

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

Box 2.4: Cost of production used in this section

In 2018, 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.[82] For individual supply regions across the east coast, Core estimated both full lifecycle costs of production and forward costs of production for 2P reserves as at 31 December 2017.

The analysis in this section compares price offers for 2020 supply with estimates of forward production costs, since over the short-term producers are likely to continue producing gas as long as they expect to recover their operating costs.

Core Energy's report on gas production costs estimated the costs of production for a range of areas. The ACCC has chosen to use the estimated forward costs for the marginal source of supply in Queensland and Victoria, as this would likely set the price floor in negotiations between gas suppliers and buyers in those states.

For Queensland, the ACCC chose Middle Surat and Roma Shelf supply region as it has material uncontracted 2P reserves (9260 PJ) that Core expects to be in production in 2020 and that Core estimated to have the highest forward cost ($5.55/GJ).

The choice of the marginal supplier in Victoria is more complicated. Based on the bargaining framework set out in box 2.6 below, the marginal supplier in Victoria comes into the analysis in the circumstances where substantially more gas is produced in the south than there is demand in the south (such that the prices start to trend towards the seller alternative). In those circumstances, the production costs of the marginal supplier in the south would set the floor in pricing negotiations. It is likely that additional production from new sources would be required for the south to reach such a state. In those circumstances, the new source of supply would likely be the marginal supplier.

It is difficult to predict what the new source of supply would be or what its forward production cost of that supplier is likely to be. For the purpose of the analysis in this chapter, the ACCC has chosen the Sole gas field as a proxy for the costs of a new marginal supplier. The Sole field is a new source of production in the south and its costs are therefore indicative of the likely costs of a new supplier. According to Core's estimates, Sole had 355 PJ of 2P reserves with an estimated forward production cost of $5.60/GJ as at 31 December 2017.[83]

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

2.4.1. LNG netback price expectations for 2020

Over the past 12 months, Asian LNG spot prices have continued to exhibit significant volatility, affecting expectations of LNG netback prices. Chart 2.2 shows the fluctuations in expected LNG netback prices at Wallumbilla for 2020, based on Asian LNG spot prices, in the period between 29 September 2017 and mid-June 2019.

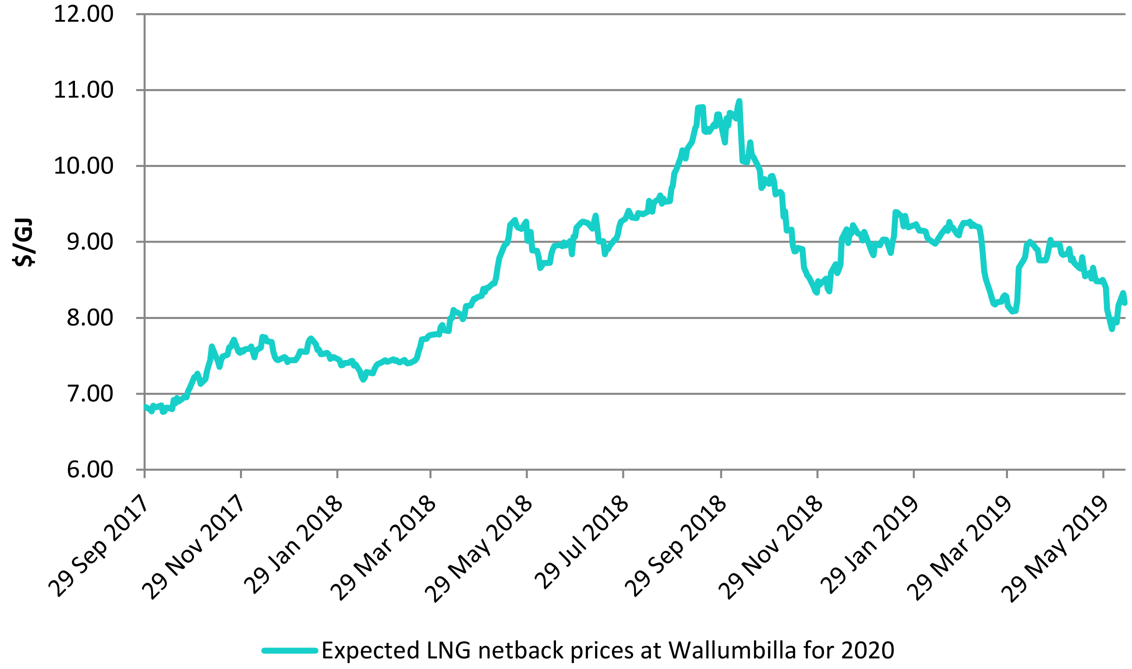
The LNG netback prices in the chart were calculated using the approach set out in box 2.3, with one difference—each point in the chart represents a daily average of expected LNG netback prices across the entirety of 2020 (compared to a monthly average in section 2.4.2 below). The chart below differs from the ACCC's regular publication of LNG netback prices,

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

83 This includes the estimated reserves in the Longtom gas field.

in that it shows how expectations of LNG netback prices for the entirety of 2020 have changed over time, rather than showing expected forward prices for each month.

Chart 2.2: Expected LNG netback prices at Wallumbilla for 2020



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

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

Chart 2.2 shows that expected LNG netback prices at Wallumbilla for 2020 have varied significantly since the end of September 2017, rising from less than $7/GJ to almost $11/GJ by October 2018. Expectations around average 2020 LNG netback prices have since softened, falling to just over $8/GJ by mid-June 2019.

These changes in expectations of Asian LNG spot prices over a relatively short period show the degree of price volatility in the Asian LNG market. While this emphasises that sudden and unexpected changes in LNG supply and demand dynamics can have significant short-term impacts on spot price expectations, it may also have implications for our assessment of prices offered relative to LNG netback price expectations. Sudden changes in price expectations may not immediately flow through to offers being made at that time, particularly where prices being offered by gas suppliers are the result of longer-term negotiations, or in instances where gas suppliers and/or buyers view changes in spot price expectations as transitory or temporary. As a consequence, where changes in LNG netback price expectations do flow through to domestic price offers, it may take time for this to be evident.

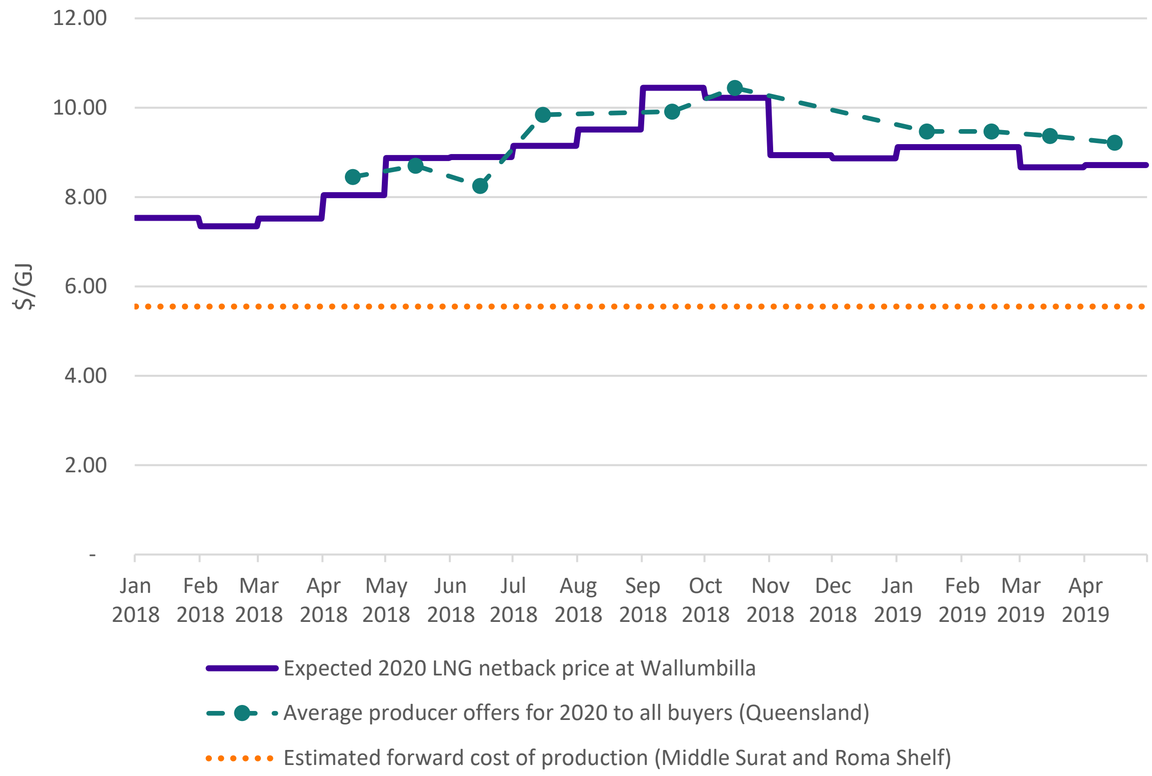
2.4.2. Domestic price offers for 2020 supply in Queensland

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

Chart 2.3 below presents quantity-weighted average prices offered by gas producers in Queensland with:

- the averages of expected LNG netback prices at Wallumbilla for 2020 in each month between January 2018 and April 2019[84],[85]
- the estimated forward costs for the marginal supplier in Queensland.

Chart 2.3: Averages of monthly gas commodity prices offered by Queensland producers for 2020 supply against contemporaneous expectations of LNG netback prices



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

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

Chart 2.3 shows that, over the period April to October 2018, the averages of prices offered in Queensland generally trended upwards, with the averages of prices offered since October at or below $9.50/GJ. Over that same period, the average of expected 2020 LNG netback prices trended upwards, peaking at $10.45 in September 2018, settling around the $9/GJ mark by April 2019.

The chart shows that the averages of prices offered by Queensland producers for 2020 supply were in line with contemporaneous expected LNG netback prices for 2020 until October 2019, and from January to April 2019 were slightly above expected 2020 LNG netback prices. Furthermore, the chart shows that the averages of prices generally increased during periods where LNG netback prices for 2020 increased (with the exception of June 2018), and subsequently decreased when LNG netback price expectations fell.

84 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 months in which no offers were made, or there were insufficient offers made for data to be published given confidentiality considerations.

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

Based on the data in the chart, it appears that the averages of prices offered by Queensland producers have been, at least in part, moving in line with LNG netback price expectations.

However, there are several considerations that should be kept in mind when interpreting the results of the chart above. On the one hand, internal board documents of key producers in Queensland indicate that LNG netback price expectations influence domestic prices offered by those producers. On the other hand, there are a number of factors that mean that the relationship between LNG netback prices and offers made by producers may not always be readily observable (see box 2.5).

Box 2.5: Considerations in comparing domestic prices to LNG netback prices

While the chart above suggests that price offers for 2020 supply made over 2018 have been responsive to movements in LNG netback price expectations, at least in part, the ACCC notes several limitations that make it difficult to be too definitive.

First, the analysis in chart 2.3 is based on a relatively small number of offers and would therefore be disproportionately influenced by outliers.

Second, a large number of prices are part of multi-year offers — for these offers, prices offered to gas users for 2020 might reflect expectations of LNG prices over the life of the contract and not just expectations specifically for 2020.

Third, producers often make offers in the course of negotiations that take place over a period of up to several months. Asian LNG prices can change rapidly, leading to subsequent sudden changes in expectations for LNG netback prices in 2020. Given this, it may take time for changes in LNG netback price expectation to be reflected in formal offers made by suppliers. In some instances, producers may also form a view that rapid fluctuations in LNG netback prices are only temporary and may make offers based on their own estimates of expected LNG netback prices.

Finally, as noted in previous reports, LNG netback price expectations are only one factor that can affect domestic prices. Other factors are also relevant, including the expected supply-demand balance, production costs and the level of competition in the market.

As shown in chart 2.2 earlier, LNG netback price expectations for 2020 have fallen over the course of 2019, and indeed have fallen since April 2019 (the end of the period covered in chart 2.2). Given that the LNG netback price expectations influence domestic prices, the ACCC would expect the lower expectations to flow through to domestic gas offers.

However, the ACCC notes that the averages of prices offered by producers in Queensland for supply in 2019 and 2020 have largely remained within the range of $8-10/GJ since May 2017.[86] This is despite relatively large movements in expectations for future LNG netback prices over that period.

The ACCC will continue to monitor how the prices offered by Queensland producers compare to LNG netback price expectations and will next report in December 2019.

The ACCC also notes that the averages of prices offered suggest that, should these offers be accepted, gas producers in Queensland are likely to receive prices well in excess of the estimated forward costs of production.

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86 Offers for 2019 supply were last presented in the ACCC's April 2019 Interim report (ACCC, *Gas Inquiry 2017–20 Interim Report*, April 2019, p. 27).

2.4.3. Domestic price offers for 2020 supply in the Southern States

As explained in our previous reports, the ACCC has adopted a bargaining framework to analyse pricing outcomes in the Southern States.[87] Under this framework, the pricing dynamics in the Southern States are different from those in Queensland. Box 2.6 explains the ACCC's bargaining framework and how it is used to assess prices offered in the East Coast Gas Market.

Box 2.6: 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 price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location, and
- the seller alternative (representing a floor in negotiations) — the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the cost of production (whichever is higher).

Where a price actually achieved in a negotiation will fall within this range is likely to depend on a number of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the Southern States, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

The supply-demand 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, all other things equal. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location.[88] 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.[89]

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

[87] ACCC, Gas Inquiry 2017–20 Interim Report, September 2017, p. 69.

[88] 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.

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

States using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the analysis below we present a buyer and seller alternative for Victoria.

Chart 2.4 shows quantity-weighted average prices offered by suppliers in the Southern States between January 2018 and April 2019 for supply in 2020 compared to the range within which gas prices would be expected to fall using the bargaining framework set out above.

The upper end of the range is the buyer alternative in Victoria—indicative of the highest price that would be expected to be offered in the Southern States under the bargaining framework—which is derived by taking averages of expected LNG netback prices at Wallumbilla for 2020 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.

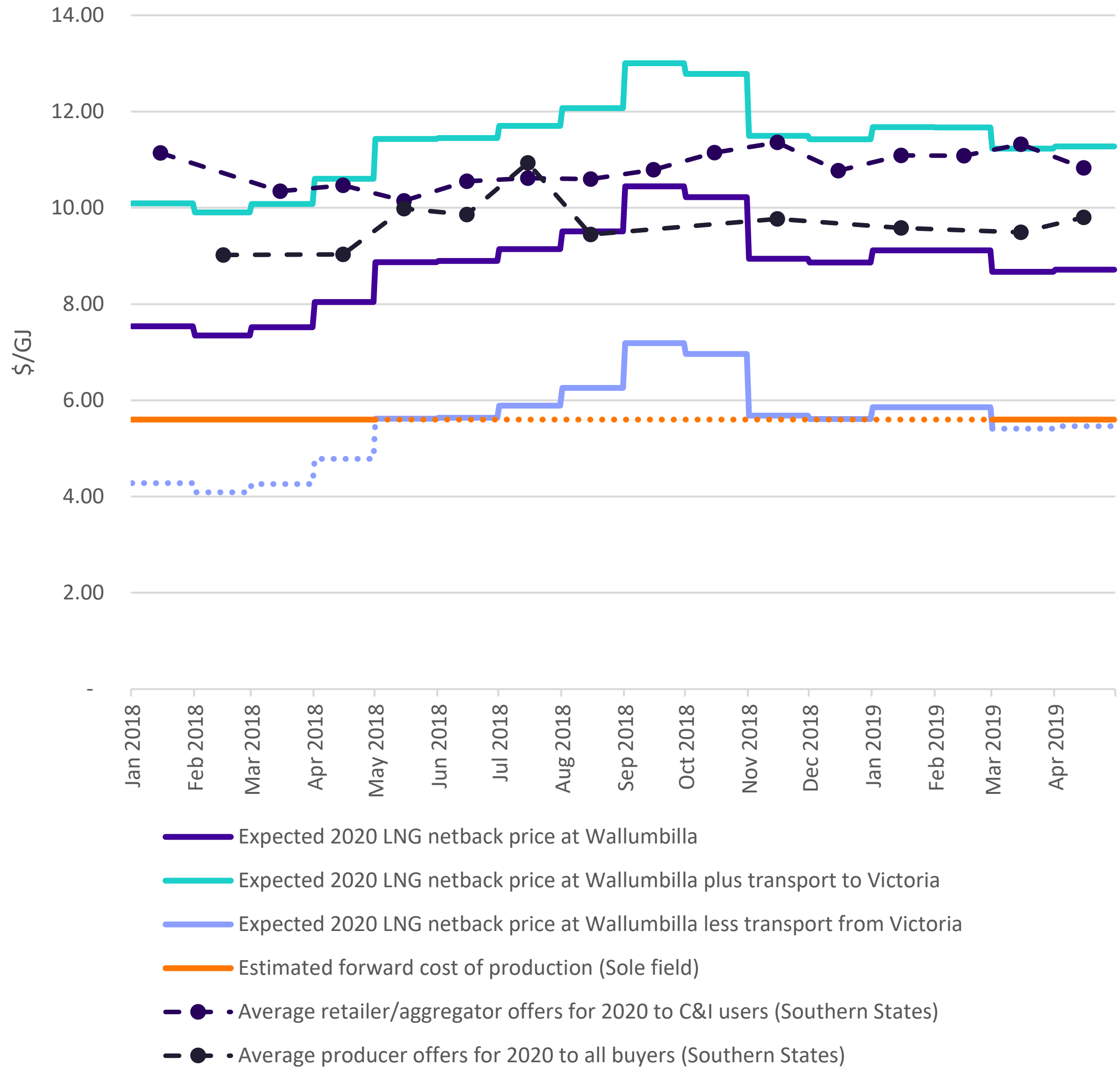
The lower end of the range is the seller alternative in Victoria, determined by the higher of:

- the averages of expected LNG netback prices at Wallumbilla for 2020 less indicative pipeline tariffs from Melbourne to Wallumbilla[90]
- the cost of production of the marginal source of supply.

The ACCC notes that the LNG netback prices and buyer and seller alternative prices do not account for other factors that may influence the prices offered to gas buyers, such as flexible non-price terms and conditions in GSAs, the contract length and retailer costs and margins.

90 Indicative pipeline tariffs are based on the costs of transporting gas from Wallumbilla to Melbourne via Sydney (for the buyer alternative), and the costs of transporting gas from Melbourne to Wallumbilla via Moomba, including processing costs at Moomba to ensure the gas meets the specifications for conversion to LNG. Costs of transportation between Melbourne and Wallumbilla (via Moomba) for north flowing gas, and between Wallumbilla and Culcairn for south flowing gas are published on the ACCC's website (https://www.accc.gov.au/system/files/Map-2-A3.pdf). An indicative tariff from Culcairn to Melbourne is published on APA's website (https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/victorian-transmission-system/). Pipeline losses and processing costs at Moomba were published in the ACCC's East Coast Gas Inquiry 2015 final report (https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015/report).

Chart 2.4: Average of monthly gas commodity prices offered for 2020 supply against contemporaneous expectations of 2020 LNG netback prices (Southern States)



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

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

Chart 2.4 shows that over the period between February 2018 and April 2019, the averages of prices offered by producers in Southern States varied between about $9/GJ and $11/GJ. The averages of producer prices offered increased over the first half of 2018, peaked in August and have since remained within a relatively small range. Over the same period, expected 2020 LNG netback prices trended upwards, reaching more than $10/GJ in September and October, before tracking around the $9/GJ mark to April 2019. As noted earlier, the expected average of 2020 LNG netback prices was just over $8.00 by mid-June 2019.

The chart shows that over this period the averages of prices offered by producers in the Southern States were between expected 2020 LNG netback prices and the Victorian buyer alternative (except in August 2018, when the average of prices offered was in line with expected 2020 LNG netback prices).

Chart 2.4 also shows that the averages of prices offered by retailers increased over the period March 2018 to November 2018, coinciding with a period in which expectations of 2020 LNG netback prices also increased. From November 2018 to April 2019, the averages of prices offered were close to or broadly in line with the Victorian buyer alternative.

Notably, the averages of prices offered by both producers and retailers were above contemporaneous expectations of 2020 LNG netback prices for much of the period covered by chart 2.4. As outlined in box 2.6, there are several reasons why the averages of prices offered by suppliers might differ from expectations of LNG netback prices at various points in time. There are also several other relevant considerations when comparing prices in the Southern States with LNG netback prices and the buyer and seller alternatives (box 2.7).

Box 2.7: Relevant considerations for the Southern States

As noted earlier, where a price actually achieved in a negotiation will fall within the buyer/seller alternative range depends on a range of factors, including:

- the expectation of the parties about supply and demand dynamics in the Southern States
- the location of the buyer.

Offers made at different points in time may reflect, amongst other things, different expectations about the supply outlook.

In addition, the chart aggregates offers made by suppliers to users located in different regions of the Southern States. The number of offers made in some months is relatively small, so changes in price averages from month to month could be influenced by the location of the users to whom the offers were made in those months.

Notwithstanding the qualifications above, it is unclear why the averages of prices offered in the Southern States, particularly by retailers, remain around the Victorian buyer alternative.

Under the bargaining framework, one reason prices might tend towards the buyer alternative is if there is not sufficient gas produced in the Southern States to meet demand and gas from Queensland is needed. This was the situation in 2017, when there was an expectation in the market that there would be insufficient gas produced in 2018 in the Southern States to meet the demand in the Southern States. As we reported in our September and December 2017 reports, prices offered by retailers at the time exceeded the buyer alternatives in the Southern States.

However, since 2017, there has been an improvement in the supply-demand balance in the Southern States, with gas from the Cooper Basin flowing south (as a result of swaps) and a fall in demand for gas from GPG. As set out in chapter 1, the projected supply-demand balance for 2020 suggests there will be sufficient gas produced in the Southern States to meet the expected demand in 2020, although the overall balance remains tight and there are some associated uncertainties.

Nonetheless, as mentioned above, the prices offered by retailers since around November 2018 are around the Victorian buyer alternative. The ACCC will continue to monitor the prices offered for supply in 2020 and investigate the drivers of those prices.

2.5. Prices agreed under GSAs for 2020

This section analyses GSAs for supply in 2020 that were executed between 1 January 2017 and 24 April 2019.

In the ACCC's April 2019 report, we began reporting on prices agreed under GSAs for 2020. The April 2019 report included GSAs executed between 1 January 2017 and 23 January 2019. So that this report covers only the prices agreed under the most recent GSAs, the analysis in this section has been limited to GSAs that have been executed since 1 January 2018. The analysis also incorporates the most recent GSAs obtained by the ACCC, which were executed between January 2019 and 24 April 2019.

Box 2.8 below sets out the ACCC's approach to reporting on prices agreed under longer-term GSAs.

Box 2.8: Approach to reporting on prices agreed under GSAs

The information in this box should be read in conjunction with information in box 2.1. The following also applies to the analysis of prices agreed under GSAs:

- For the purpose of the analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. For the purpose of the analysis of retailer prices, we have only included GSAs between retailers and C&I users.
- In contrast to the preceding analysis of offers and bids, we estimated prices under GSAs using assumptions relating to key variables (oil prices, foreign exchange rates and CPI) based on the latest market expectations for those variables for 2020.[91]
- These market expectations have changed since we last reported on GSA prices in April. Oil prices, foreign exchange rates and the CPI level are lower than was expected in April. A reduction in oil prices and the CPI level reduces expected GSA prices and a reduction in the foreign exchange rate increases expected GSA prices. The net effect of the change in expectations is lower expected GSA prices than would be expected using our previous assumptions.
- As in the case of the offers analysis above, the reported prices are based on the wholesale commodity price of gas and do not include separate charges for transporting gas to the user's location or any other ancillary costs.
- In addition to average prices, we are also reporting corresponding average load factors and take or pay quantities. Both load factor and take or pay are a measure of the level of flexibility allowed under the contract.
- We have previously categorised producer prices based on the location of the gas resources most likely to supply the relevant GSA. In this report, we categorise GSA prices by the location of the delivery point rather than the location of the source of the gas. We have made this change to the way we categorise producer GSAs so that we can report GSA prices that are more relevant to gas users as they more accurately reflect the regional variation in prices that users experience. This is a minor technical change and both categorisation methods yield substantially similar results because gas is generally supplied from the resources most proximate to the relevant delivery point. For this reason, GSA prices as categorised in this report are readily comparable, ceteris paribus, to GSA prices categorised by the method used in our previous reports.

Table 2.3 shows average gas prices expected to be paid for supply in 2020 under GSAs entered into by producers and retailers. The prices in this table are not directly comparable to the prices previously reported in the April 2019 report due to the exclusion of 2017 GSAs

[91] In all estimates of 2020 GSA prices in this report, the following assumptions were made, where relevant:
- Consistent with Commonwealth Treasury methodology, the AUD/USD exchange rate for 2020 is expected to vary around the current rate. The exchange rate assumption applied to GSAs in this report is 70.13 US cents to the Australian dollar. It is based on the monthly rate published by the RBA for June 2019.
- The expected Brent crude oil price for 2020 is equal to the average price of 2020 future contracts quoted by CME Group as of 9 July 2019.The CPI assumptions used to estimate GSA prices in this report are based on actual CPI where available and 2.5 per cent thereafter.

and changed pricing assumptions. Further, both producers and retailers have only entered into a small number of new GSAs for 2020 in the early months of this year.

Table 2.3: Expected 2020 wholesale gas commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2018 and 24 April 2019)[92]

Type of supplier	Average gas commodity price ($/GJ)	Gas commodity price range ($/GJ)
Producers (QLD)	8.99	8.55–9.81
Producers (VIC, SA and NSW)	9.72	8.87–10.83
Retailers (QLD)	10.33	
Retailers (VIC, SA and NSW)	10.74	9.20–11.58

Source: ACCC analysis of information provided by suppliers.

Table 2.3 shows that in the period between 1 January 2018 and 24 April 2019, the average of prices in GSAs executed in the Southern States is higher than the average of prices in GSAs executed in Queensland. The range of agreed prices in the Southern States is also wider than the range of agreed prices in Queensland. This north-south range differential is consistently observed in GSA prices and likely reflects a greater diversity of prices across various locations in the Southern States.

Producer prices are higher in Queensland than we reported in April 2019. Over the period from 23 January 2019 to 24 April 2019, producers entered into a small number of new GSAs for 2020 supply. The increase in Queensland producer prices is due to the removal of GSAs executed in 2017 from the reported average.

We did not report 2020 retailer prices disaggregated between the north and the south in our April report due to the limited number of relevant contracts. Retailer prices for both Queensland and the Southern States are higher than the combined average we reported in April 2019. This increase is due to retailers in the Southern States entering into GSAs at higher prices more recently.

2.5.1. Evolution of GSA prices over time

The GSA analysis in the preceding section provides a snapshot at a point in time. The analysis in this section shows how GSA prices have evolved over time.

Throughout the inquiry, the ACCC has presented an invoiced time series, which showed average prices paid at a particular point in time under all applicable GSAs. In this report, we present a time series of average GSA prices agreed at a particular point in time. This time series better demonstrates the evolution of the market prices, because in an invoiced price series the average of prices is a lagging indicator of market prices due to the influence of prices paid under legacy GSAs.

Chart 2.5 presents the quantity-weighted average of prices under GSAs executed in half yearly intervals from the second half of 2016 to the end of 2018. The approach for calculating these prices is set out in box 2.9. Each point on the chart represents a

92 Pricing assumptions applied to GSAs in this section are the same as applied in Section 1.3 above. 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.

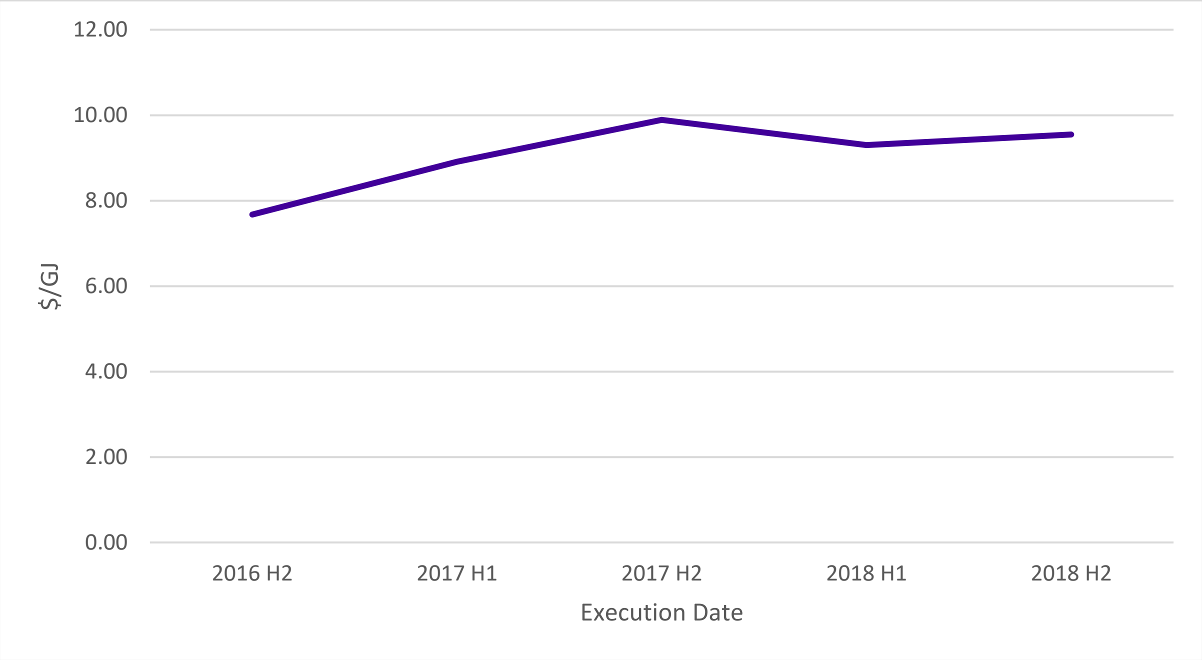
quantity-weighted average of base commodity prices under all the applicable GSAs executed in that half.

Box 2.9: Approach to creating the GSA time series

The series in chart 2.5 includes GSAs executed with C&I gas users (excluding retailers and GPG gas users). For this series the ACCC:

- included GSAs executed at arm's length
- included GSAs from both producers and retailers
- included GSAs for delivery across the whole of east coast (i.e. Queensland and the Southern States)
- included GSAs for supply of at least 0.5PJ and for a term of at least 12 months
- included only fixed price GSAs (i.e. excluded any GSAs linked to oil or JKM)
- excluded GSAs with unique non-price arrangements that are not reflective of the market as a whole
- calculated a quantity-weighted average price of each GSA using the base commodity price (i.e. not including separate transportation or other ancillary charges) and the first years annual contract quantity specified in the GSA
- calculated a half yearly quantity-weighted average based on all the applicable GSAs that were executed in that half yearly interval, irrespective of the term of the GSA.

Chart 2.5: Quantity-weighted average wholesale gas commodity prices in GSAs executed in the East Coast Gas Market in each half yearly interval from the second half of 2016 to the second half of 2018.



Source: ACCC analysis of information provided by suppliers.

Chart 2.5 shows that prices agreed by C&I gas users in newly executed GSAs rose sharply between the second half of 2016 and the second half of 2017. If the data in the chart were disaggregated into quarterly prices, it would show that in the third quarter of 2017, the GSA prices peaked, on average, above $10/GJ. We have previously reported that some C&I gas users faced extremely difficult market conditions at that time.[93]

Average GSA prices subsequently softened to around $9/GJ in the first half of 2018, as more gas was made available to the domestic market following the signing of the Heads of Agreement between the Australian Government and the LNG producers in October 2017.

The prices in newly executed GSAs increased in the second half of 2018. The data obtained by the ACCC up to the end of April 2019 (not shown in the chart) shows the GSA prices reached around $10/GJ in the first quarter of 2019. This puts these prices in line with those observed in the third quarter of 2017, although it should be noted that a relatively small number of contracts were signed in the first quarter of 2019.

2.5.2. Load Factor and Take or Pay Level

In this section, we report on the quantity-weighted average of load factors and take or pay levels in GSAs. Load factors and take or pay levels are key terms and conditions in GSAs, which influence the value of the gas supplied under the GSA. While load factor and the take or pay level are non-price terms and conditions, they can nevertheless be costly for a seller of gas to provide to a user. As such, the level of these terms and conditions in GSAs are an important qualifier when considering the commodity price of gas under the GSA.

Table 2.4 shows the quantity-weighted average load factor and take or pay level under GSAs for supply in 2020, entered into by producers and retailers.

The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. A load factor above 1 allows a gas buyer to vary the amount of gas they are using subject to their needs. The higher the load factor the more difficult and costly it is for the seller to manage their obligations to supply gas under the GSA. This is because the seller will need to reserve gas to meet peak demand that may not otherwise be used for the rest of the year.

The take or pay level is the percentage of the contracted gas that must be paid for by the buyer whether or not the buyer actually takes delivery of the gas. A GSA with a take or pay level of 0% is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

Buyers may value the ability to purchase gas flexibly under a GSA by taking more or less gas than the contracted amount. A GSA with a degree of flexibility may also be more costly for a seller to supply than a GSA with no flexibility. In order to provide flexibility to a buyer, a seller is required to maintain the ability to supply gas that the buyer may not purchase. In order to be in a position to supply gas on demand a seller must maintain sufficient processing, transport, and/or storage capacity. When, gas is not taken up by a buyer under the GSA the seller may have to sell this gas urgently at market prices and may have missed previous opportunities to sell that gas to other buyers at a higher price.

93 ACCC, Gas Inquiry 2017-20 Interim Report, September 2017.

Table 2.4: Expected 2020 average Load Factor and average Take or Pay Level in the East Coast Gas Market (under GSAs executed between 1 January 2018 and 24 April 2019)

Type of supplier	Load Factor	Take or Pay Level %
Producers (QLD)	1.03	0.87
Producers (VIC, SA and NSW)	1.61	0.93
Retailers (QLD)	1.13	0.86
Retailers (VIC, SA and NSW)	1.14	0.89

Source: ACCC analysis of information provided by suppliers.

Table 2.4 shows that the average of load factors in producer GSAs is lower in Queensland than in the Southern States. This difference is due to a small number of GSAs in Southern States with very high load factors. In contrast, the average of load factors in retailer GSAs are similar between Queensland and the Southern States.

Take or pay levels are similar across Queensland and the Southern States and between producers and retailers. On average, retailers have more flexible take or pay arrangements than producers. Producers and retailers in the Southern States have marginally less flexible take of pay arrangements, on average, than producers and retailers in Queensland.

The differences in the level of flexibility offered under the different categories of GSA in Table 2.4 may be driven by the capability of sellers and requirements of buyers. Both gas producers and gas retailers can provide flexibility to buyers if they are adequately compensated for doing so. Retailers may be in a better position to provide flexibility in GSAs to C&I gas users as they can manage changes in the demand for gas on a portfolio basis and may also have access to underground or pipeline storage to manage the variations.

2.6. Industrial gas prices in overseas jurisdictions

To provide context for price reporting published in the Gas Inquiry 2017-20 Interim reports, the ACCC engaged S&P Global Platts (Platts) to prepare a report on delivered gas prices paid by industrial gas users in a range of countries, including Australia. This report will be made available on the ACCC's website.

The analysis in the Platts report covers a wide range of country-specific characteristics, including gas production, gas demand, geographic location, gas market regulation, taxation policy, and market characteristics.

The Platts report presents average country-level delivered prices paid for gas by industrial users.[94] These prices include wholesale gas prices, transportation and delivery charges, retailer margins and other charges. To derive estimates of gas prices paid, Platts collected data from industrial users in different countries to derive estimates of gas prices paid by end users. Data collected included data from Platts' proprietary database, publicly-available information and surveys conducted with industrial users in different countries. Survey data was primarily used as a comparison for price levels when other data sources were available and was only used for regions where other forms of data was lacking. The survey was designed to ensure that all data collected was directly comparable to all other data collected.

In contrast, the ACCC's price reporting in other sections of this chapter (and in previous Interim reports), focuses on commodity gas prices rather than delivered gas prices. For this

[94] The Platts report also covers residential gas prices, which have not been included in this report.

reason, the prices reported in other sections of this chapter are not directly comparable to those in the Platts report.

However, as part of work undertaken on retailer costs and margins, the ACCC has estimated delivered gas prices for C&I gas users who purchase gas from Origin Energy, AGL and EnergyAustralia (see chapter 4 for more information). While the approach adopted for estimating these prices is different to that adopted by Platts, the ACCC's notes that our estimates of delivered retail prices are broadly in line with those estimated by Platts. As can be observed in chart 4.3, delivered gas prices for C&I gas users in the East Coast Gas Market were approximately $12.80/GJ. In their report, Platts estimate that industrial users on the east coast of Australia pay between USD$8-11/MMBtu, which converts to a range of about $10.87–$14.94/GJ, with a simple average of AUD$12.91/GJ.[95]

Based on this, the ACCC considers that Platts' estimates of delivered gas prices in Eastern Australia are likely to be broadly in line with prices actually paid by the bulk of C&I gas users. For this reason, in comparing the east coast gas prices to international prices in this section, we use the estimated east coast gas prices provided by Platts. This ensures that the analysis in this section is based on comparable estimates.

Table 2.5 presents data on Platts' estimates of prices paid in overseas gas markets. Because these estimates are country averages, they may not reflect prices in different regions within a country.[96] Furthermore, table 2.5 identifies which countries are importers or exporters, and provides a brief overview of country-specific characteristics.

[95] Invoiced prices were converted to USD/MMBTU based on: a conversion factor from GJ to MMBTU of 1.055:1; and an exchange rate of 0.6977.

[96] For example, as noted on p.9 of Platts' report, gas spot prices in the US state of Maine have at times exceeded USD$100/MMBTU while prices in the south of the US were below $0/MMBTU.

Table 2.5: Delivered industrial gas prices in Australia and overseas in 2018, USD/MMBtu

Country	Average industrial delivered gas price USD/MMBtu	Importer / exporter	Effect of tax policy on industrial prices	Country-specific characteristics
Eastern Australia	$8–11	Exporter	Low	-
Switzerland	$21.54	Importer	Moderate	Substantial cross-border pipeline connections.
Sweden	$14.06	Importer	High	Reliant on pipeline imports from Denmark.
China	$12.88	Importer	Low	Supply of gas from domestic production, LNG and pipeline imports from Russia and CIS nations. China is slowly transitioning to an open market.
South Korea	$12.66	Importer	Low	Sources all gas through LNG imports. Kogas has a monopoly on domestic gas sales.
Ireland	$12.23	Importer	Moderate	Increasing domestic production reducing reliance on gas supply from the UK.
Denmark	$11.70	Exporter	High	Domestic production exceeds domestic demand.
Portugal	$9.45	Importer	Moderate	Supply from a single LNG import terminal and a single pipeline connection with Spain.
Germany	$8.96	Importer	High	Pipeline connections with several major supply countries.
UK	$8.92	Importer	Low	Supply of gas from domestic production, LNG and pipeline interconnections with mainland Europe.
Spain	$8.84	Importer	Moderate	Declining demand due to renewables is decreasing LNG demand while gas pipeline imports from North Africa remain significant.

Netherlands	$8.63	Importer to exporter	High	Major supplier to Europe and home to a major gas-trading hub (the Title Transfer Facility).
Peninsular Malaysia	$7.88	Exporter	Low	East Malaysia is Asia’s largest LNG exporter. Peninsular Malaysia domestic demand largely met through domestic production.
Turkey	$6.94	Importer	Moderate	Pipeline connections with Russia and Iran.
Canada	$4.68	Exporter	Low	Abundant supply in Western Canada and low demand and export potential keep prices low.
Mexico	$4.53	Importer	Low	Increasingly reliant on importing gas from the US.
United States	$4.06	Exporter	Low	A recent boom in shale gas production has led to a surplus of low-cost gas.
Saudi Arabia	$1.25	Neither	Low	Highly regulated gas market.

Note: Gas can be exported or imported through pipeline connections or as LNG transported by ship.

Table 2.5 shows that there is significant variation in the prices paid by industrial users in different countries. This ranges from $1.25/MMBtu in Saudi Arabia to $21.54/MMBtu in Switzerland.

Aside from Saudi Arabia, the three North American countries have the lowest average industrial gas prices, with the US, Canada and Mexico having average industrial gas prices of $4.06/MMBTU, $4.68/MMBTU and $4.53/MMBTU respectively. These three countries also have the smallest cross-country variation of any region in the report.

In contrast, Europe has the largest variation in cross-country prices. Turkey, which is located close to major gas-producing countries, has the lowest average industrial gas prices in Europe at $6.94/MMBtu. Switzerland has the highest average prices, followed by Sweden at $14.06/MMBtu.

In Asia, Peninsular Malaysia has the lowest average industrial price at $7.88/MMBtu compared to $12.66/MMBtu in South Korea and $12.88/MMBtu in China. Average industrial prices in South Korea and China were the highest across all of the countries included in the report with the exception of Sweden and Switzerland.

Prices in Australia, broadly speaking, were in line with those in several European countries, including Germany, the UK, Spain and Portugal. While they were higher than those in Peninsular Malaysia, average prices in Eastern Australia were below those in both China and South Korea.

Countries with low demand tend to have higher gas prices. The 6 countries in the study with the lowest gas demand all have relatively high industrial gas prices. Conversely, the US, which has annual gas demand of about 750 Billion Cubic Metres (BCM), has very low prices;[97] Germany, which has low prices despite being a gas importer, has gas demand about 50 per cent higher than that on Australia's east coast.

As a general rule, countries that are net importers of gas tended to have higher industrial gas prices than exporters. An exception to this rule is Eastern Australia, which has average prices in line with countries that are net importers of gas. In contrast, the US and Canada, which are also net exporters, had prices significantly below those in Eastern Australia. However, this is predominantly due to the unique characteristics of the East Coast Gas Market.

Section 2.6.1 below sets out the key factors that explain cross-country variation in international prices reported by Platts. Section 2.6.2 below discusses the unique characteristics in the east coast of Australia and how these differ to the countries covered in the Platts report.

2.6.1. Factors explaining variation in prices between countries

Broadly speaking, there are two key drivers of observed differences in prices across countries—demand/supply dynamics, and taxation polices and gas market regulation.

Demand/supply dynamics

Demand/supply dynamics refers to the interaction between total gas demand and gas production within a country. Based on the countries included in the report, there are four demand/supply related factors that appear to explain observed differences in prices.

First, as noted earlier, countries that are net importers of gas typically have higher prices. Conversely, countries that are net exporters tend to have lower prices — this is particularly

97 1 BCM = 33.85 PJ.

so in countries where domestic supply is high relative to domestic demand and export capacity. For example, following the recent development of shale gas in the US, domestic production outstripped growth in domestic demand and LNG liquefaction capacity. As a result, gas prices in the US are low compared to most countries, and remain well below prices seen in the US 10 years ago.[98] Similarly, abundant production in Western Canada, combined with relatively low domestic demand and limited ability to export (via pipelines to the US), has ensured that gas prices remain low. Eastern Canada's connectivity to shale gas production areas in the US, which provides a source of low-cost gas, has contributed to low gas prices in Eastern Canada despite low gas production.

Second, countries which have access to diverse sources of gas supply typically have lower industrial gas prices. This is because diversity of gas supply creates competitive pressure among gas suppliers. For example, despite having high gas demand and being a net importer, Germany's industrial gas prices remain relatively low due to having pipeline connections with the Netherlands, Denmark, Norway and Russia. This was not always the case. Prior to having pipeline connection with Russia, German prices traded at a material premium to those in the Netherlands.

Turkey and the UK are two other countries that benefit from access to diverse gas supply. Turkey has access to pipeline gas through multiple pipelines connections with Russia, Iran and the Commonwealth of Independent States (CIS nations) and LNG through an import terminal. The UK has access to gas from Europe through several pipelines and access to LNG through a number of LNG import terminals.

Conversely, a lack of diverse supply is seen in those countries with higher prices. Portugal, which has access to gas through a single LNG terminal and a single pipeline connection with Spain, has prices above those of nearby countries, including Spain. Ireland, which has only a single pipeline connection with the UK, sees even higher prices (although recent increases in domestic prices has reduced the reliance on pipeline imports).

The third factor is the cost of gas production and/or procurement in each country. Gas suppliers with lower production and/or procurement costs will be willing to accept lower prices, all other things equal. This is because, in theory, the minimum prices that gas suppliers would be willing to accept would be equal to their production and/or procurement costs—in this sense, production and/or procurement costs can create a de facto price floor for gas prices.

The US is perhaps the most obvious example in this respect. The recent ramp up in gas production in the US has been through the development of low-cost gas, primarily from shale gas fields and associated gas from shale oil fields. Low production costs, along with excess supply, has led to low prices.

South Korea, which sources the entirety of its gas through LNG imports, has prices significantly above those in the US. This is not surprising given LNG prices typically trade at a premium to US gas prices. That said, most of South Korea's LNG is imported under relatively competitively-priced long-term contracts, which has led to industrial prices in South Korea being lower than in other LNG importing nations.

The final factor is cross-country differences in gas demand, which could impact on prices in a number of ways. Gas producing countries with high gas demand are likely to see greater investment in gas exploration and appraisal, and thus greater gas production, which will put downward pressure on gas prices (all else equal). Similarly, high gas demand in importing countries is likely to lead to higher levels of investment in gas transmission pipelines to transport gas from other countries—this would provide access to gas from different supply

98 For example, Henry Hub prices have varied in the range between $3–5/MMBtu since 2010, whereas between 2000 and 2010 there were periods where Henry Hub prices exceeded $10/MMBtu.

regions and in turn create competitive tension between different suppliers and lead to lower prices. Finally, high gas prices would provide incentives for industrial gas users to switch away from gas consumption, where possible, or to relocate to countries with lower gas prices. This could explain the low levels of demand in countries with high prices.

Government taxation policies and gas market regulation

The second key determinant of cross-country gas price variation is government taxation policy and gas market regulation.

A number of countries impose direct taxes on gas usage, which, assuming some of this tax burden is passed onto gas buyers, would directly increase gas prices paid by industrial users. Furthermore, taxes on gas substitutes, such as coal, would increase the demand for gas and place upward pressure on prices, all other things equal.

Despite being a net exporter of gas, Denmark has industrial gas prices above those in most European countries due to high tax rates—Denmark has a tax rate of 25 per cent levied on industrial gas consumption. Switzerland, which has the highest industrial gas prices of the countries in the study, has a tax rate of more than 25 per cent on industrial gas consumption and natural gas users are also required to pay a levy to ensure 'national gas security'. Prices in Switzerland continue to remain high despite Switzerland having substantial cross-border pipeline connectivity, particularly with Germany.

Conversely, prices paid by industrial users in several countries continue to remain below global market price benchmarks due to government gas market regulation. Saudi Arabia, of all the countries surveyed, has the most regulated gas market, with domestic prices subsidised at $1.25/MMBtu. While Saudi Arabia has large gas reserves, it does not export significant amounts of gas and domestic production is rationed to gas users. While China is slowly transitioning to an open market, industrial gas users are still paying artificially low gas prices (although it should be noted that industrial prices in China are, over time, becoming more aligned with market prices). Finally, government subsidies in South Korea, as well as regulation of Kogas, a monopoly gas supplier in South Korea, keeps prices lower than they otherwise would be.

2.6.2. Characteristics of the East Coast Gas Market

The East Coast Gas Market has a unique set of characteristics compared to the countries covered in the Platts report. These characteristics, alongside the analysis above, provide context around gas prices paid by C&I gas users in Eastern Australia relative to those in other jurisdictions.

Relative to the countries in Platts' report, the East Coast Gas Market:

- is a liberalised market
- is closely linked to international LNG prices
- has high production costs
- has relatively small domestic demand, and
- has its biggest new sources of supply linked to demand via relatively high priced long distance transmission pipelines.

Many of the largest exporting countries around the world benefit from having abundant low-cost supply and relatively limited export capacity. This helps to keep the domestic prices relatively low in countries like US and Canada. One of the key reasons gas production costs in US are relatively low is that there is cross subsidisation from the production of oil.[99,100] Even though the US is connected to the higher priced international LNG markets via LNG export terminals, the total export capacity of those terminals is very small relative to the size of the domestic market and relative to the total level of gas production. Canada has no LNG export facilities and exports gas via pipelines into a well-supplied US market.

In contrast, the east coast of Australia has largely already developed its known low-cost gas fields. As the ACCC reported in previous reports, production from conventional gas fields in the Bass Strait and the Cooper Basin is in decline, with new production sources of supply from these regions coming from lower volume, deeper and lower quality gas fields. The largest uncontracted reserves in the east coast are coal seam gas reserves located in Queensland. Based on a report from Core Energy, the estimated lifecycle production costs of most of those reserves are only marginally below the average delivered gas prices paid by industrial users in US and Canada. Given such production costs, it is not feasible that domestic prices in Australia would be comparable to the domestic prices in US and Canada.

Further influencing the pricing dynamics in east coast are the facts that the East Coast Gas Market supply-demand balance is tight and the market is closely linked to the international LNG markets through significant excess capacity in the LNG export terminals. As we reported in December 2018 report, the LNG producers 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 next 10 years.[101] This means that in a given year, the LNG producers could export a quantity of gas, in addition to meeting their long-term LNG export commitments, roughly equivalent to 2/3 of total domestic demand in the East Coast Gas Market. As a result, domestic gas buyers compete with international LNG buyers for their gas and the domestic gas prices in the East Coast Gas Market are shaped more by the LNG netback prices than production costs.

Increasing the delivered prices of gas even further are the high transportation costs. As mentioned above, the largest uncontracted gas reserves in the East Coast Gas Market are in Queensland, whereas the bulk of the domestic demand is located in the Southern States. These demand centres are connected to the Queensland reserves through long-distance transmission pipelines. The ACCC's 2015 inquiry found that the majority of transmission pipelines on the east coast were using their market power to engage in monopoly pricing. The prices in many of the legacy contracts entered into at that time have increased in line with inflation since that inquiry.

The combination of these factors mean that the delivered gas prices paid by C&I gas users in the East Coast Gas Market are higher than those paid by industrial users in gas exporting countries. However, they are still lower than the domestic prices paid by industrial users in South Korea and China, which purchase Australian LNG. Prices in these countries is also understated due to the government regulation in China and South Korea, which has artificially depressed industrial gas prices in those countries.

Gas markets in China, both industrial and residential, have traditionally been subject to price regulation. This has been the case for industrial and residential gas prices. Since the early 2000s, China has slowly been transitioning to an open gas market, with industrial prices becoming more aligned with market prices. Industrial prices in China, however, remain below broader market prices.

99 Dewar, Gee and Baker, *Preparing for an abundance of natural gas*, Boston Consulting Group, https://www.bcg.com/en-au/publications/2019/united-states-us-abundance-natural-gas.aspx.

100 DiSavino, *U.S. natural gas prices turn negative in Texas Permian shale again*, Reuters, https://www.reuters.com/article/us-usa-natgas-waha-negative/u-s-natural-gas-prices-turn-negative-in-texas-permian-shale-again-idUSKCN1SS1GC.

101 ACCC, Gas Inquiry 2017-20 Interim Report, December 2018, p. 36.

In South Korea, almost all industrial gas supply comes from Kogas, which has a near monopoly on the Korean import market. While a monopoly would be expected to charge higher prices, Kogas is subject to government regulation of its ‘wholesale to retail’ margins. This serves to keep industrial prices relatively low (given Korea sources all of its gas from LNG markets).

In contrast, the East Coast Gas Market is a liberalised market. Taxes on gas consumption are relatively low and governments have generally avoided implementing policies or regulatory settings designed to artificially depress the domestic prices.

2.7. Prices in facilitated markets

2.7.1. Victorian wholesale gas futures

The Declared Wholesale Gas Market (DWGM) allows market participants to trade in futures contracts for gas in Victoria. While recent months have seen a relative decline in trading activity in gas futures relative to the final quarter of 2018, the Victorian gas futures market continues to deepen.

Trading activity over the first 5 months of 2019 was relatively low, with monthly trades as follows:

- in January 2019, there were 60 quarterly contracts traded for 2019 futures and no trades for 2020 futures
- in February 2019, there were 20 quarterly contracts traded for 2019 futures and no trades for 2020 futures
- in March 2019, there were 87 quarterly contracts traded for 2019 futures, and 25 quarterly and 5 yearly contracts traded for 2020 futures
- in April 2019, there were 25 quarterly contracts traded for 2019 futures, and 80 quarterly and 20 yearly contracts traded for 2020 futures
- in May 2019, there were 26 quarterly contracts traded for 2019 futures, and 40 quarterly and 5 yearly contracts traded for 2020 futures.

The level of trading activity over the first five months of 2019 — 363 quarterly contracts and 30 yearly contracts traded — was broadly in line with that that over the final quarter of 2018, which saw 351 quarterly contracts and 55 yearly contracts traded.

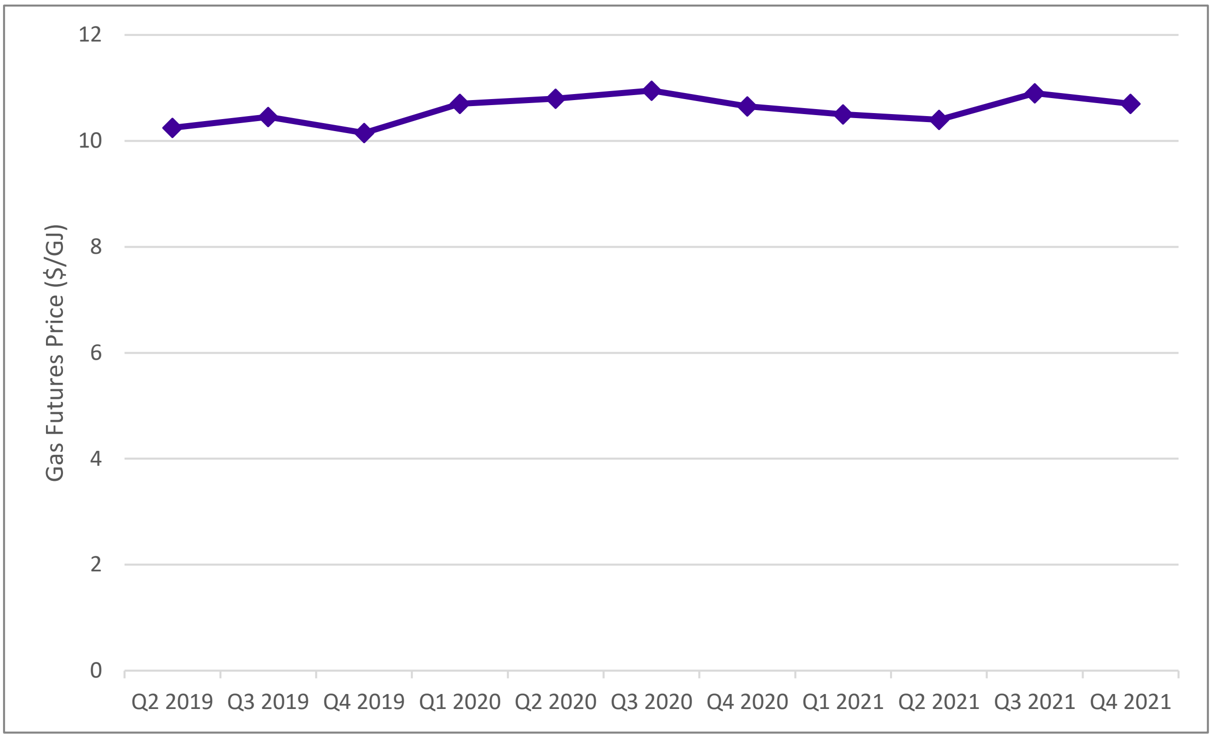
While this is a reduction in average monthly trading activity compared to the last quarter of 2018, it still represents substantial growth on the first three quarters of 2018, which saw a total of 228 quarterly and 15 yearly contracts traded.

In total, in the 12 months from 3 June 2018 to 29 May 2019, 857 quarterly contracts and 95 yearly contracts were traded amounting to approximately 11 PJ of gas.

The amount of open interest in quarterly futures contracts has also continued to grow since the ACCC last reported on gas futures, increasing from 522 outstanding contracts as at the time of the April 2019 report to 628 outstanding contracts as at the time of this report. This, along with the year on year increase in trading activity, suggests that the Victorian gas futures market is continuing to become more liquid. This is consistent with the feedback provided by commercial and industrial users that they are increasingly prepared to enter short term trading markets to manage their own risks around gas prices (see chapter 3).

The futures prices shown in chart 2.6 indicate that market participants expect gas prices in the DWGM to remain relatively stable throughout 2019, 2020 and 2021, with future spot prices expected to remain between $10/GJ and $11/GJ over this period.

Chart 2.6: Victorian DWGM futures prices from Q2 2019 to Q4 2021



2.7.2. Prices paid in short-term trading markets in the past 12 months

Chart 2.6 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 June 2018 to June 2019. The chart also shows the absolute price difference between the markets in Queensland and the Southern States.

Chart 2.7: Daily prices paid in domestic short-term trading markets, June 2018 to June 2019

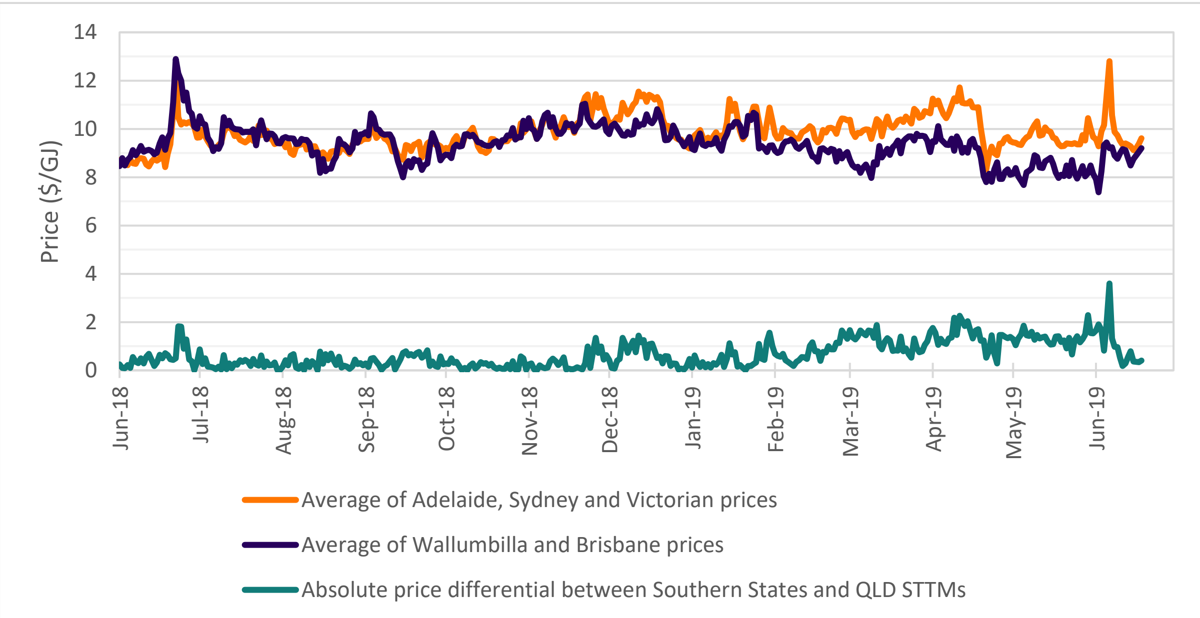


Chart 2.6 shows that since the April 2019 report, prices paid in short term trading markets in Queensland and the Southern States have fluctuated within $7/GJ–$13/GJ range.

Prices paid in northern and southern markets tracked each other closely over most of 2018 and early 2019, but have largely diverged since March 2019 on. Between July and late November 2018, the absolute price difference between Queensland and the Southern States STTMs remained below $1/GJ. In the period since then, however, the absolute price difference between Queensland and the Southern States STTMs has increased, peaking at $4/GJ in June. By the end of June, the simple average of the prices in short-term trading markets in the Southern States was about $9.60/GJ, compared to $9.20/GJ in Queensland.

Prices in domestic STTMs in the Southern States over Q2 2019 were higher or in line with those seen in Q2 2018—the simple average of prices was $9.95/GJ for Q2 of 2019 compared to $8.33/GJ for Q2 2018 (a 19.4 per cent increase).

In Queensland, the price changes have been lower than those in the Southern States. The simple average of prices in Queensland STTMs was $8.65/GJ for Q1 2019 compared to $8.21/GJ for Q1 2018 (a 5.4 per cent increase).

The quantity of gas traded in short-term trading markets in the Southern States has increased. In aggregate 25.91PJ of gas was traded in Adelaide, Sydney and Victoria in Q2 2019 compared to 21.05 PJ of gas Q1 2019.

In Queensland, the quantity of gas traded on the Brisbane STTM fell to 5.29 PJ in Q2 2019, from 9.44 PJ in Q1 2019.

Changes in quantities traded across recent quarters could relate to seasonal variations in energy demand (such as gas for residential heating in winter), as well as changes in demand for gas to be used for LNG production.

3. Recent experiences of C&I gas users

3.1. Key points

- C&I gas users continue to report difficult circumstances with the primary concern being gas prices and their impact. The price of gas was one of the top three concerns of all gas users surveyed. Lack of competition among gas suppliers and long-term uncertainty were the second and third most reported concerns.
- High gas prices have led to a number of C&I gas user businesses becoming unviable. In the first quarter of 2019, RemaPak, a Sydney-based producer of polystyrene coffee cups, and Claypave, a Queensland-based brick and paving manufacturer, went into administration. Dow Chemical also cited rising gas costs as an important contributing factor to its plans to shut its manufacturing plant in Melbourne.
- Large C&I gas users (with annual gas consumption of a least 1 PJ/a) and small gas users seeking gas report different market experiences. Larger C&I gas users generally noted a willingness by producers and retailers to engage and negotiate, with users receiving a number of responses to requests for gas supply. Smaller C&I gas users that have recently been active in the market for 2020 supply reported fewer suppliers making offers. In some cases users received just one offer.
- C&I gas users are adjusting to the export exposed nature of higher gas prices through a variety of gas reduction strategies.
    - Some C&I users are considering, or implementing, a switch to alternative energy types. One user has converted a boiler from gas to coal and another boiler from gas to woodchips. Australian Paper, is progressing with an energy-from-waste plant after successful completion of a $7.5 million feasibility study. A third user is considering switching from using electricity from its co-generation gas powered generator to using electricity from the grid.
    - The processes around users contracting for gas are also changing. Some C&I gas users have developed sophisticated arrangements for sourcing gas; switching from being supplied by a retailer to organising their own gas supply and transportation. One user, Incitec Pivot, has moved upstream and is developing a gas tenement as a joint venture with Central Petroleum.
- Some C&I gas users continue to report frustrations that some producers are refusing to respond to requests for offers and insist that users participate in the supplier's own expression of interest processes. Other users also reported delayed or no response from retailers to inquiries to supply gas.

3.2. Introduction

During April, May and June 2019, we surveyed a range of commercial and industrial (C&I) gas users to gain insight into their most recent experiences in the gas market. This is the fifth occasion the inquiry has sought the views of gas users, with previous surveys and meetings conducted in September and July 2018, and September and December 2017.

Many of these gas users consume large quantities of gas (over 1 PJ per year) for their production processes across a diverse range of sectors such as mining, manufacturing, agriculture, and food production. These C&I gas users represent sectors that are important contributors to the Australian economy and are also large employers, particularly in regional areas. Many C&I gas users are supplying in highly competitive international markets and are very sensitive to small fluctuations in their input costs.

In recent years, C&I gas users have been actively participating in the public discourse about the East Coast Gas Market. In particular, users have expressed concerns about consequent exposure of the domestic market to international prices following the development of the Queensland LNG export projects, as well as government moratoria and environmental controls on gas developments. Some of the impacts that gas users have reported include: reduced ability to obtain gas supply offers, a change in how gas is procured, an increase in prices offered, shorter supply terms offered, increasingly restrictive terms and conditions, and some offers being made on a 'take it or leave it' basis.

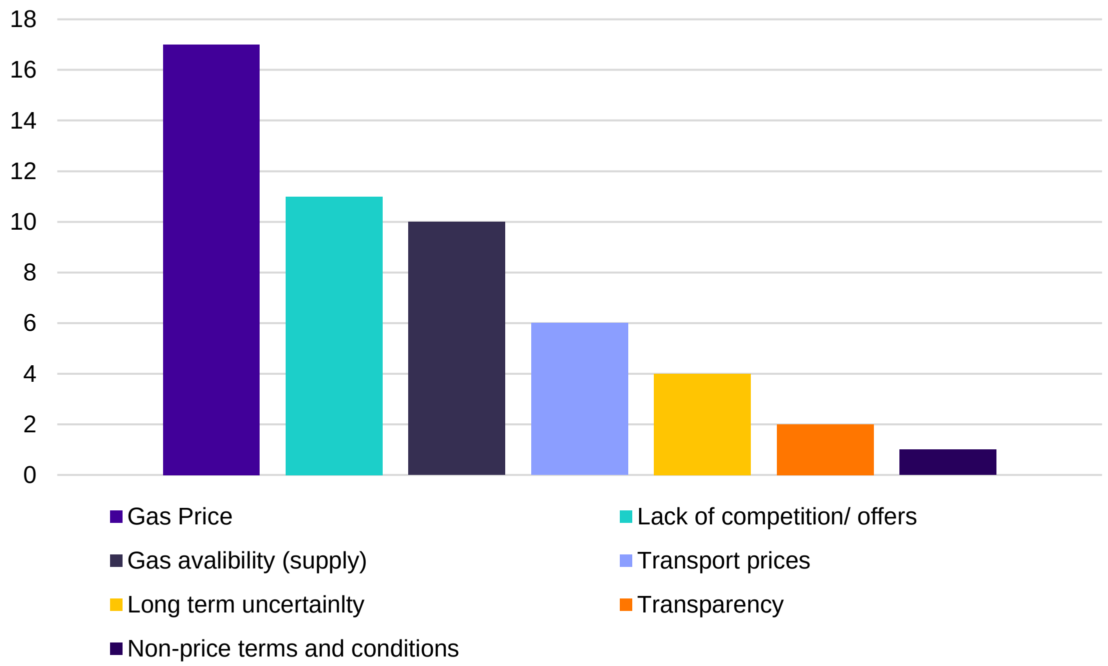
The combined effects of these pressures on gas prices has played a contributing factor in the closures of RemaPak, Claypave and the Dow Chemical manufacturing plant in Melbourne this year.

Between April and June 2019, the ACCC invited large and small C&I gas users to take part in meetings and a survey. We received 18 survey responses from C&I gas users from across the east coast (predominantly in the Southern States) with a combined annual consumption of around 80 PJ/a. This represents over a third of the C&I market. These users represent a broad range of sectors and use gas for a variety of purposes, such as a feedstock to production processes, and as a heat source for producing steam or for drying processes.

We asked these users to rank the key issues they were facing in the market. Chart 3.1 shows users' top three concerns from seven options.

As in the previous survey when considering current market conditions, 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. Availability of supply, lack of competition amongst gas suppliers and long-term uncertainty were also prominent concerns.

Chart 3.1: Top three concerns for C&I gas users



Note: The y-axis represents the number of participants that ranked each concern in their top three. There were 17 responses to this question.

3.3. Users continue to report difficult circumstances, with their primary concerns being gas prices and their impact

3.3.1. Higher gas prices are influencing the investment decisions of C&I gas users

Many of the C&I users we consulted are exposed to international competition in the markets in which they supply their products. As a result, these gas users report that they cannot pass on their gas cost increases to their customers because they would become uncompetitive with their overseas rivals. Instead, these users must absorb higher gas costs, unless they can implement other strategies to mitigate the effects.

C&I users whose gas use makes up a large proportion of their cost of production (over five percent) continue to be particularly affected. In response to higher gas prices, many users have reported making short-term decisions to enable continued operation of their businesses. However, the longer-term implications of higher gas prices are now being further considered as they assess their longer-term viability. In particular, those users who have to make major decisions on plant upgrades or large maintenance spends into the next decade are carefully assessing the long-term sustainability of their business.

In June Brickwork's chief executive Lindsay Partridge told the *Australian Financial Review* the company would consider not replacing assets in certain states, such as NSW, unless the gas supply situation was resolved.[102]

> *"Why would we replace an asset where there is no guarantee we will have gas in 10 to 20 years' time?" Mr Partridge is quoted as saying. "We are already bringing in bricks from around the world out of sheer desperation. Unless the situation improves, we'll let the assets run down here and invest elsewhere."*[103]

A number of users have expanded operations overseas rather than increasing their Australian portfolio. Users stated significantly lower gas prices overseas (particularly in the US) as one of the biggest contributing factors in these decisions.

A lesser impact has been felt by those C&I users for whom gas constitutes a smaller proportion of their costs (less than five per cent). For these users, higher gas prices still affect profitability but have a proportionally smaller effect. However, many of these users are large consumers of electricity, so the impact of higher gas prices can also be felt indirectly to the extent that higher gas prices contribute to higher electricity prices.

C&I gas users have generally sought to adopt methods to mitigate the short-term impact of increased gas costs, including through;

- energy efficiency improvements
- fuel switching
- postponing capital expenditure
- reducing headcount or pay increases
- deferring investments or expansions, and
- changing shift/usage patterns.

However, many have told us that current gas price levels are not sustainable for them in the long-term, and profitability is described as borderline by several users (because of gas cost increases). Again, one user that is looking to further reduce its gas price exposure has made

[102] Mark Ludlow, Gas Prices push firms to the wall, Australian Financial Review, 4 June 2019, Accessed 24 June 2019.
[103] Mark Ludlow, Gas Prices push firms to the wall, Australian Financial Review, 4 June 2019, Accessed 24 June 2019.

the point that each additional mitigation project has ever decreasing returns for each dollar invested.

One regional user said expanding operations with a new $15 million site in another regional area was now in doubt. This user explained:

> *"We were paying about $5GJ. We now pay about $11 and are locked in for the next few years until 2021. Gas cost last month was about $100,000. At this stage we are seeing indications north of $15 GJ (plus transmission) for 2021 forward. This is compressing our margin on an expansion project enough that it is now in doubt… We are increasing prices to our clients—but seeing some small customers convert to imported disposable products instead of our reusable product."*
>
> *Large east coast gas user, June 2019*

3.3.2. Questions about longer-term viability of operations persist

A number of manufacturing businesses closed in 2019.[104] These closures follow numerous warnings and significant concerns raised by users as noted in our December and July 2018 reports about the business impacts of gas market conditions. In our most recent consultations, users maintained concerns about the longer term viability of their operations. Some users who have previously expressed sustainability concerns have undertaken efficiencies through staff reductions. One user linked 100% increases on the delivered price of gas in the previous three years as the main contributing factor in staff redundancies. One user put it this way:

> *"Prices (Including transport) remain unsustainably high and unless resolved represent a challenge to the ongoing competitiveness and sustainability of our operations."*
>
> *Large east coast gas user, May 2019*

C&I user 1:

Kagome is a seasonal employer in regional Victoria. During the peak of summer harvest teams work in three eight-hour shifts, non-stop 24 hours a day, seven days a week, from the end of January until March. The company processes about 200 000 tonnes of tomatoes at its Echuca headquarters for pantry staples including Leggos and Masterfoods. The Echuca plants processes about 45 per cent of all the processed tomatoes consumed in Australia. [105]

In June its chief executive Jason Fritsch told the *Australian Financial Review* soaring gas prices had pushed the processor to the cusp of economical sustainability.

Mr Fritsch said the company's energy bill had increased from $3.4 million in 2016 to $5.1 million in 2019. The gas component increasing from $2.3 million annually to $3.5 million this year.

Mr Fritsch said the business could not pass these costs on to customers. ''We have to wear that ourselves, we are on the cusp of basically not being sustainable if energy prices keep going up,'' Mr Fritsch told The *Australian Financial Review*. ''It is becoming increasingly difficult to remain sustainable." [106]

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104 Nick Toscano and Paul Sakkal, Altona site to shut: Union sounds jobs alarm on gas crisis, 28 May 2019.

105 Kagome, About Us, Accessed 24 June 2019 see also Alex Sampson, Kagome's claim to be the world's best tomato processor is no idle boast, The Weekly Times, 23 March 2016 Accessed 24 June 2019 and Mark Ludlow, Gas Prices push firms to the wall, Australian Financial Review, 4 June 2019, Accessed 24 June 2019.

106 Mark Ludlow, Gas Prices push firms to the wall, Australian Financial Review, 4 June 2019, Accessed 24 June 2019.

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. One user put it this way:

> *"We don't expect current prices to return to historical pricing [of $3-$5GJ]. But, the current prices are too high and users are left with no alternatives. Our energy bill has doubled and this increase in energy cost is mostly due to higher gas prices. The gas bill increase alone is $5 million in the past few years."*
>
> *Large east coast gas user, May 2019*

One of the east coast's largest C&I gas users, Incitec Pivot, reported preparing for the closure of its Gibson Island plant before a last minute agreement with Australian Pacific LNG secured gas at a viable price.[107]

Incitec Pivot employs about 400 workers at its Gibson Island chemical plant. Gibson Island uses gas as a feedstock to produce industrial chemicals and fertilisers, distributing to more than 4,000 cotton, sugarcane and sorghum farmers in Queensland and northern New South Wales.[108]

> *"Up until the day we signed the gas supply agreement with APLNG, we had two teams working diligently—a red team and a blue team. The red team was responsible for preparations to immediately implement shut down plans if we didn't secure the gas at an affordable price. The blue team was responsible to complete a gas supply deal that places IPL in a position to operate the plant without incurring an unacceptable risk of losses over the next investment period. The final decision was not made until the day of the announcement. Until that time it was a very real probability that hundreds of jobs would be lost had a collaborative deal not been reached. The current agreement puts IPL in a reasonable risk position to invest in the plant and operate for a three year period, and to test all available options for longer-term supply, including the potential for gas supply from joint venture block with Central Petroleum should that block prove viable."*
>
> *Tim Lawrence, Vice President Group Energy Strategy, Incitec Pivot*

3.4. There is a difference in experience between large and small C&I users, however high prices are impacting all

Large C&I gas users (over 1PJ/annum) and small C&I gas users report different experiences when contracting for gas. These differences were reported in relation to engagement from retailers, the ability to contract with producers and the willingness of producers and retailers to negotiate terms.

C&I gas users who have been in the market for gas reported receiving higher gas price offers compared to December 2018. As noted above, gas prices are one of the top three concerns of C&I gas users. As reported in chapter 2, average gas price offers from producers between January and April 2019 were mostly below $10/GJ. For the same period, average gas price offers from retailers ranged between $10–12/GJ. These prices are significantly lower than the peak-prices offered in early 2017 (over $20/GJ) but many C&I users report that these prices continue to pose significant difficulties for them and are playing a part in business closures.

[107] Incitec Pivot, IPL welcomes commencement of Northern Gas Pipeline, 4 January 2019, Accessed 4 July 2019.
[108] Incitec Pivot media release, Incitec Pivot Limited confirms gas supply for Gibson Island manufacturing operations to continue through 2022. 4 June 2019, Accessed 24 June 2019.

There have been some high-profile agreements announced recently, such as APLNG's agreements with Incitec Pivot, Orora and Orica.[109] Under the terms of these agreements Orica will buy 10.2PJ of gas between 2021 and 2025 and Orora will buy up to 6PJ of gas between 2023 and 2026.[110] Orora also signed a three year deal for 3.3PJ of gas starting in January 2020 with Senex Energy.[111] While these agreements are encouraging, our most recent survey of C&I gas users suggests a more diverse experience.

Larger C&I users (over 1 PJ/a) generally noted a willingness by producers and retailers to engage and negotiate, with users receiving a number of responses to a request for prices. Smaller C&I gas users that have recently been active in the market for 2020 supply reported fewer suppliers making offers.

Many users reported receiving higher priced offers for longer-term supply. Some users also reported only receiving shorter-term contract offers (1–3 years). This means that as the remaining legacy long-term contracts conclude, users will continue to seek new arrangements more frequently over coming years.

Some larger users have reported receiving offers for longer 5 to 10 year contracts, however variables for delivery and capacity were too diverse to identify discernible trends.

> *"Gas prices at the wholesale level are in the double-digits level for 2020 and beyond despite falling LNG netback prices."*
>
> *Large east coast gas user, May 2019*
>
> *"It is a sellers' market. Offers and contracts presented are very inflexible. There is no room for good faith discussion. For example, daily flexibility and take or pay – a few years ago these were common terms up for discussion, but not anymore. The contracting environment is almost like a reverse auction space to maximise the price of gas."*
>
> *Large east coast gas user, May 2019*
>
> *Three indicative prices received in May 2019, all of which are significantly higher than our contracted price. Market commentary we have received suggests prices are projected to increase.*
>
> *East coast gas user, June 2019*

Some C&I gas users are offered prices that are oil-linked (compared to fixed price or CPI linked prices). With less offers to choose from, 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 reported increased concerns about the risk of higher future market offers due to unfavourable movements in oil and LNG prices, and the Australian dollar.

3.4.1. Users express concerns about a lack of offers for gas supply

C&I gas users continued to raise concerns about the lack of competition among 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.

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109 Incitec Pivot media release, Incitec Pivot Limited confirms gas supply for Gibson Island manufacturing operations to continue through 2022. 4 June 2019, Accessed 24 June 2019 see also Angela Macdonald-Smith, New gas deals show market is working, *Australian Financial Review*, 5 July 2019, Accessed 5 July 2019.

110 Angela Macdonald-Smith, New gas deals show market is working, *Australian Financial Review*, 5 July 2019, Accessed 5 July 2019.

111 Senex Energy Ltd Media Release, Senex and Orora agree domestic gas supply contract, 1 May 2019, Accessed 5 July 2019.

As discussed above, there is a difference in the level of offers being received between larger and smaller C&I users. In some cases users received just one offer. Some users report that, even though they received several offers, the majority of offers received did not fully meet the requirements they had set out in their request.

In December, 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 2019.

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 some users reported that there was a lack of firm offers being made and that several suppliers had advised they had no gas to offer beyond 2020. This is cause for some concern and the ACCC will continue to monitor and report on the situation and we expect that, consistent with more recent market practices, more contracts for 2020 are likely to be signed later in 2019.

> *"Suppliers are typically 'not ready' to discuss 2020 supply when approached in late 2018 and typically on their terms or sought EOI."*
>
> *Large east Coast gas user, May 2019*

Some users expect prices to remain higher due to international LNG market dynamics, and so they are keen to negotiate competitive, long-term supply arrangements now. Other users are of the view or remain hopeful that prices may further decrease (whether as a result of the ADGSM being triggered or market forces) and are holding back on making long-term gas purchasing decisions until then.

There were a small number of C&I gas users we consulted that had already contracted for 2020 and were seeking gas supply offers for 2021 and beyond. Users reported that while several suppliers had engaged in constructive discussions, firm offers were less forthcoming and pricing indications were still high. These users are hoping to lock in contracts by the end of the 2019.

3.4.2. C&I users report more suppliers are using EOI processes to sell gas

C&I gas users report suppliers' preference for EOI processes is growing[112] with one C&I user reporting invitations to participate in EOI or auction style processes by five suppliers.

The processes around gas users contracting for gas are also changing. Many users continue to report frustrations concerning their engagement with retailers and producers. Users report some producers are refusing to respond to requests for offers and insist that users participate in the supplier's own expression of interest processes. Some users also reported delayed or no response from retailers to inquiries to supply gas.

> *"Gas prices received this year are substantially higher than last year and this year we have been asked to bid for gas in an Expression of Interest (EOI) rather than the supplier offering a price.*
>
> *East coast gas user, June 2019*

Another user put it this way:

> *"We have observed a spike in EOI processes and a desire to hold gas off until the latter points of the year…Some suppliers refused to participate [when we went out to*

[112] ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 61 and ACCC, Gas Inquiry 2017–2020—Interim Report, September 2017, p. 48.

market] as they were running their own EOI process later in the year, others did not have any gas to offer. Some did not respond at all."

Large east coast gas user, May 2019

A third user stated:

"There is no certainty for gas supply and price. Gas buyers now have to enter into multiple EOIs with gas suppliers and producers to try and secure some gas for their businesses."

Large east coast gas user, May 2019

Concerns around the transparency of EOI processes have also been raised by a number of users. One user said:

"In our last submission we made a competitive price offer, but the supplier obviously found another user to make more profit from…We aren't given adequate feedback from EOI processes"

Large east coast gas user, June 2019

3.4.3. Gas is predominantly offered for shorter term periods and under less flexible terms

Some C&I gas users were seeking agreements for only one year, partly in recognition of market uncertainty and pricing levels. Other users had a preference for long-term (more than six year) agreements to help underpin long-term business decisions. Some users find it difficult to make long-term investment decisions without certainty in gas supply given it is a significant input cost. One user sought a seven year contract, but reported that no producer was able or willing to provide certainty over that period.

Some C&I gas users questioned why suppliers are charging a premium for greater take-or pay flexibility,[113] suggesting that in a tight market, suppliers will readily find demand for the uncontracted gas and it could be resold. They also reported increasingly restrictive terms and conditions, including high take-or-pay conditions.

"There appears to be an increase in suppliers requiring higher take or pay conditions—90 per cent appears to be the standard."

East Coast gas user, June 2019

[113] Take-or-pay: A contract term specifying the minimum proportion of the gas supply agreement's annual contract quantity that the buyer is required to take in a particular year. The buyer is required to pay for this minimum quantity of gas regardless of whether they use it.

3.5. C&I gas users are increasingly open to a range of options to deal with current market conditions

We continue to see a trend of C&I users moving away from their traditional supply approaches,[114] which often consisted of re-contracting with the same retailer year-on-year. With the changed market conditions discussed above, users are looking at a wider suite of options. Based on user comments, there is some indication that short-term, large impact efficiency options might be starting to be exhausted and users are now considering other strategies such as natural gas alternatives, sourcing gas directly from producers, participating in short-term trading markets and supply via proposed LNG import terminals.

3.5.1. Natural gas alternatives and gas reduction strategies

Following the trend observed in our September 2017 and July 2018 reports,[115] a large number of C&I users are investigating the use of alternative fuels. In many cases, gas is used for heat to produce steam. Alternative fuels for these processes include coal, which varies in cost depending on circumstances but for some users can be around half the cost of gas at current prices.

Some users we spoke with have recently made significant investments converting boilers to run on alternative fuels to replace or significantly reduce their gas consumption. Other users are considering doing the same. For instance, if implemented, Australian Paper's waste to energy proposal could reduce its gas use by up to 4 PJ each year.[116]

For many users, the fuel cost comparison is much better despite the investment costs for changes to plants. A further benefit is that switching to these gas alternatives would provide more certain fuel supply and stability of pricing in the current market environment.

A few users have reported being approached for waste burning or wood burning alternatives for energy generation. However, some C&I gas users are reluctant to move to more carbon intensive fuels given the environmental impact

Some C&I gas users are adjusting to the export exposed nature of higher gas prices through a variety of gas reduction strategies. The majority of users surveyed have implemented gas-reduction strategies and continue to explore further opportunities to minimise gas consumption. These strategies fall broadly into two categories, switching fuel type and finding efficiencies.

C&I user 2:

This regional C&I gas user employs about 1200 workers in regional Australia. The business undertook capital costs totalling tens-of-millions of dollars to switch one boiler from gas to coal. This user was purchasing gas at about $11GJ while comparable coal costs are about $5.40GJ.

"We can't pass on gas price increases to our buyers as it's a global commodity. Most of our product is sold in to the American market where gas is $3.20 (USD) GJ, so we can't cost recover in the US market."

"We are a family owned—Australian business. There is a significant cost if we close. We keep people employed. Gas prices have had an impact on our expansion plans."

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114 ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 63.

115 ACCC, Gas Inquiry 2017–2020—Interim Report, September 2017, p. 52 and ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 63.

116 Australian Paper, Energy from Waste Project Summary, p. 6. 27 September 2018, Accessed 14 June 2019.

C&I user 3:

This large eastern gas user employs about 2500 workers across Australia. The company is undertaking a feasibility study to switch energy types from gas to using electricity from the electricity grid. This user said projected increases to gas prices with CPI over $11.50 would make their business unsustainable.

"Gas Prices and Transportation prices as well as long-term certainty are now jeopardising the viability of one of our plants, which may push us back to grid electricity supply, stranding an expensive asset. Gas costs plus pipeline costs are trending to a level where returning to grid power is a better business proposition now."

Case study 4:

One large eastern gas user's gas reduction strategies were reached through efficiencies leading to a 1PJ/a decrease in use. These changes were categorized as "financially essential" as increasing gas prices and consumption at previous predicted levels would have had a significant adverse impact on their profit margin. This user has undertaken feasibility studies to use alternative fuel through incineration of residential and commercial waste instead of gas.

3.5.2. C&I gas users are changing the ways they source gas

The processes around users contracting for gas are clearly changing. Some C&I users have developed sophisticated arrangements for sourcing gas: switching from being supplied by a retailer to organising their own gas supply and transportation.

Moving from retailers to producers

Large C&I gas users are generally more likely to consider producer supply offers than they traditionally have as these offers have tended to be lower priced than retailer offers. Users also noted producer supply offers have fewer cost components because transport is sought separately. Therefore, users reported that it was easier to understand what is being priced.

However, obtaining gas directly from producers comes with additional challenges. Producer offers can also have less flexible supply conditions (for example 100 per cent take-or-pay) and different pricing structures, which can be an adjustment for users. Some C&I gas users have become market participants and secure their own transport arrangements to enable them to purchase from producers, which involves additional time and resources. One user described it this way:

> *"We decided to manage our own transport capacity to reduce retailer margins… it saves us about $1/GJ."*
>
> *Large east coast gas user, June 2019*

As discussed in section 4.5.4, information collected by the ACCC shows that supply by producers to C&I users has increased over recent years, from around 114 PJ in 2017 to 143 PJ in 2018, with 134 PJ contracted for 2019. In 2017, 47 percent of gas supplied to C&I users was sourced directly from producers. By 2019 this figure had jumped to 55 percent.

However, not all C&I users have the option of entering into arrangements directly with producers. Some producers specify a minimum annual quantity of gas that a user must acquire to be eligible for their supply, and many smaller C&I gas users do not consume enough gas to qualify.[117] As we reported in the December 2017 report, one approach being trialled by smaller users is the formation of a buyers group (authorised by the ACCC),[118] to aggregate demand from a group of smaller users to attract direct wholesale offers from producers.[119]

Some users have gone even further upstream, with several examples over the past few years of C&I users partnering with producers to underpin new supply production. A recent example is Incitec Pivot's joint venture with Central Petroleum. This tenement will supply gas from 2022.[120]

Switching to short-term trading markets

As we reported in July 2018[121] and December 2017,[122] an increasing number of large C&I gas users have been using short-term trading markets (STTMs) to manage 'overs and unders',[123] particularly since take-or-pay rates have increased in their gas supply agreements, reducing their flexibility. We previously reported that a number of users were considering switching to these trading markets for their entire loads from 2018 onwards. Several users did start trading on these markets this year and they have reported generally positive experiences and see their entry now as just another business risk to manage.

C&I users who switched or increased exposure to trading markets for 2019 told us that they are generally well ahead (in pricing terms) of where they would have been with a wholesale or retail offer they received for 2019 gas. As shown in section 2.7.2, average prices paid in STTMs this year were generally lower than the offers received in 2018 for 2019 supply.

This user explained it this way:

> *"On occasion we have sourced gas from the Northern Territory through Mount Isa, and Moomba rather than the STTM."*
>
> *Large east coast gas user, June 2019*

This user explained their decision to join the STTM this way:

> *"We did not set out to switch to the STTM but as the gas offers we received were too high we have gradually increased the percentage of the gas we buy on the STTM. We manage the risk and have contingencies in place for when prices get too high in periods of peak demand."*
>
> *Large east coast gas user, June 2019*

However, one user raised concerns about the length of time it takes to become a market participant. This user stated:

> *"We are currently going through applications with AEMO for STTM participation and have been told that the application process takes up to six months."*
>
> *Large east coast gas user, June 2019*

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117 For example, some suppliers unwilling to supply C&I users under certain quantity thresholds (of 4 or 10PJ/a). ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 65 and ACCC, Gas Inquiry 2017–2020—Interim Report, September 2017, p. 44.

118 ACCC, The Eastern Energy Buyers Group—Authorisations—A91594 & A91595, Final Determination 22 November 2017.

119 ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 65 and ACCC, Gas Inquiry 2017–2020—Interim Report, December 2017, p. 51.

120 120Incitec Pivot media release, Incitec Pivot Limited confirms gas supply for Gibson Island manufacturing operations to continue through 2022. 4 June 2019, Accessed 24 June 2019.

121 ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 66.

122 ACCC, Gas Inquiry 2017–2020—Interim Report, December 2017, p. 48.

123 In this context, the term short-term trading markets is used broadly to refer to all trading markets across the east coast, including the Sydney, Adelaide and Brisbane STTMs, the Victorian DWGM and the northern Gas Supply Hubs.

New sources of gas

Many C&I users have been engaged in discussions with the entities considering constructing LNG import facilities on Australia's east coast. As reported previously, users generally see the entry of new suppliers and new supply in the market as beneficial.[124]

Manufacturers including Brickworks and Perdaman Group, and gas wholesaler Weston Energy have signed up as customers for Santos' Narrabri project, if the project is approved.[125]

[124] ACCC, Gas Inquiry 2017–2020—Interim Report, July 2018, p. 65.
[125] Santos, Media Centre, Santos signs MOUs with Brickworks and Weston Energy for Narrabri gas, 9 May 2019, Accessed 24 June 2019.

4. Retailer pricing

4.1. Key points

- Over 2014–2018, the major gas retailers' average margins on gas sales to mass market and small and large C&I customers were high and well in excess of the margins the ACCC would expect these businesses to receive.[126]
- Average delivered gas prices received by the major retailers have increased over recent years as the East Coast Gas Market has shifted from a low-priced domestic only market to one that is exposed to relatively higher international gas prices.
- The retailers' cost of supplying customers also increased during this period as wholesale gas prices have risen. However, due to low cost gas obtained by the retailers under long-term legacy contracts, average costs have been slower to increase and, as a result, retailers have earnt higher margins across their portfolios more recently.
- Average margins from mass market customers were between 19 and 23 per cent across the east coast for the five year period from 2014 to 2018. While the retail gas market has developed over this period, it is still relatively concentrated. Many of the impediments to effective competition identified in the ACCC's Retail Electricity Pricing Inquiry are likely to also be present in the market for mass market gas customers.
- For C&I gas users, average delivered prices have increased over the past few years, reflecting the changed east coast pricing dynamic. Across the east coast, average margins earned by the major retailers from C&I customers increased from 13 per cent in 2014 to 28 per cent in 2018.
- Volumes supplied by the major retailers to this broad group of C&I users have fallen substantially, from 158 PJ in 2014 to 93 PJ in 2018, with 78 PJ contracted for 2019. However, this decline has largely been taken up by supply from smaller retailers Alinta Energy, Shell Energy Australia, and Power and Water Corporation and by an increase in direct contracting with C&I users by gas producers:
    - Alinta, Shell and PWC have collectively increased their supply to C&I users from 1.5 PJ in 2017 to 33 PJ contracted for 2019.
    - Supply to C&I users by producers increased from 114 PJ in 2017 to 143 PJ in 2018, with 134 PJ contracted for 2019.
- While producers provide an alternative source of gas supply for large C&I users, many smaller users are likely to remain reliant on retailers. C&I users who are only able to obtain supply from one retailer appear particularly affected by a lack of competition.
- The ACCC is concerned with the high margins it has found in retailers' supply to mass market and C&I customers. We will continue to monitor and analyse margins in the retail gas market to more fully understand the extent to which the high margins reflect current supply-demand dynamics (including lower cost legacy contracts) or reflect longer term structural and competition issues.
- Ultimately, pricing outcomes depend on the level of supply and diversity of suppliers. As we have emphasised throughout this inquiry, the key way to improve pricing outcomes for C&I users is to have more lower cost gas production in the southern states and a greater diversity of suppliers.

[126] The ACCC has used EBITDA (earnings before interest, tax, depreciation and amortisation) as the measure of retail gas margins presented in this report. This accounts for profits after cost of goods sold and retail operating costs are deducted, but does not include an allowance for a return on capital. To the extent that these costs are significant, a margin that accounts for this (such as EBIT) would be lower, however the ACCC has not conducted an assessment of an appropriate return on capital for this report.

4.2. Introduction

Retailers deliver gas to a range of different customers, including residential, small to medium enterprise and C&I customers, as well as gas powered generators (GPGs) and other wholesale customers. Gas is purchased at the wholesale level and bundled with transmission, distribution and other ancillary services, depending on the customer's delivery requirements. The three largest retailers in the East Coast Gas Market are AGL, EnergyAustralia and Origin (referred to in this chapter as the major retailers). Together, the major retailers supply a large portion of C&I users and around 75 per cent of small gas customers in southern and eastern Australia.[127]

As previously reported, during 2016 and 2017 many C&I users found it difficult to secure gas supply, as offers from suppliers were limited and very highly priced. The ACCC found earlier in this inquiry that most of the highly priced offers in early 2017 were made by the major retailers, as producers were mostly inactive at the time.[128] We have also found that, while the level of price offers fell from the 2017 peak and have since stabilised, retailer prices have remained higher than producer prices on average. Given these developments and the important role that retailers have played in supplying the bulk of C&I demand in the East Coast Gas Market, the ACCC has analysed the revenues generated by the major retailers from the C&I market, the costs they face in supplying customers, and estimated their margins.

In December 2018, we reported preliminary results of this analysis using the aggregated data of the major retailers showing the various components of the delivered price of gas. Our preliminary review found that retail margins made up around 15–21 per cent of total revenue across the East Coast Gas Market and across all gas customers from 2014 to 2017.[129]

Since the December 2018 Interim report, we have collected further information from the major retailers on revenues and costs for 2018 and conducted a detailed examination of the data provided to determine the average prices paid by particular customer types in each state across the east coast, and estimated the average margins received.[130]

This chapter presents the ACCC's findings from this analysis over the five year period from 2014 to 2018 – a period that covers the development and operation of the LNG trains in Queensland and the East Coast Gas Market's exposure to international prices. The results of this analysis are based on information collected from the three major retailers.

This chapter is structured as follows:

- Section 4.3 provides a snapshot of the major retailers' supply to mass market and C&I customers as at the end of 2018
- Section 4.4 discusses the ACCC's approach to collect and analyse the information used for our reporting on retailer pricing and margins
- Section 4.5 presents the results of our analysis and discusses them in the context of our other findings made during the gas inquiry.

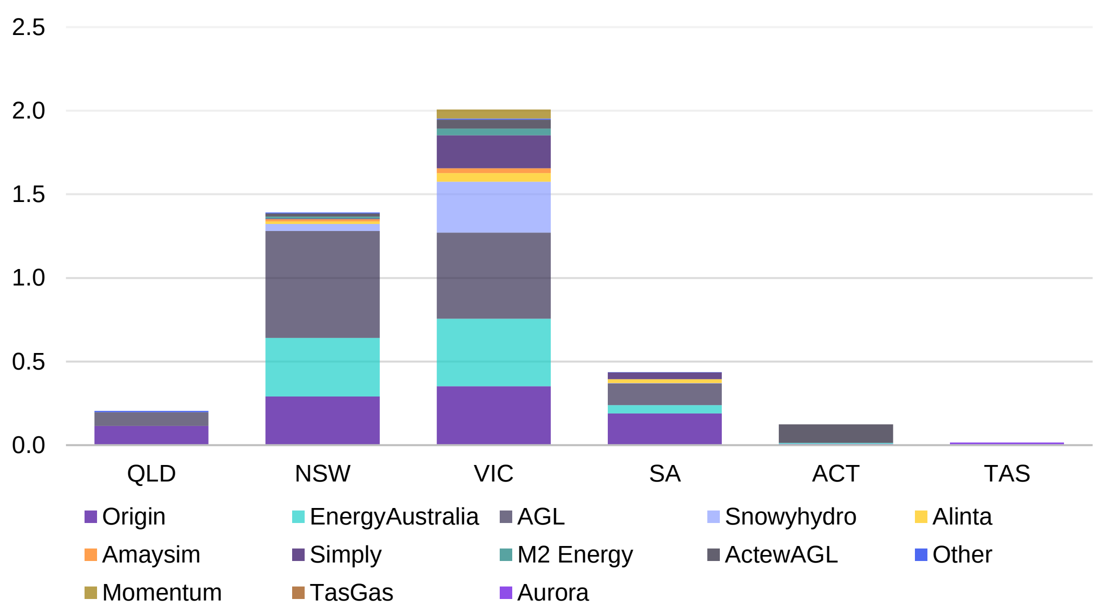
127 AER, *State of the Energy Market 2018*, p. 46.
128 ACCC, *Gas Inquiry 2017–2020—Interim report*, July 2018, p. 41.
129 ACCC, *Gas Inquiry 2017–2020—Interim report*, December 2018, p. 117.
130 States included in this analysis include Queensland, Victoria, South Australia and New South Wales (including the ACT). Tasmania is not included as the major retailers do not supply gas in that state.

4.3. Retail market snapshot

4.3.1. Mass market customers

More than 15 authorised retailers supply mass market customers across all parts of the East Coast Gas Market. The biggest three retailers are AGL, EnergyAustralia and Origin which collectively supplied 75 per cent of customers in 2018. Chart 4.1 shows the mass market shares of the major retailers across the east coast, by customer number.

Chart 4.1: Mass market customer share in 2017 (number of customers, millions)

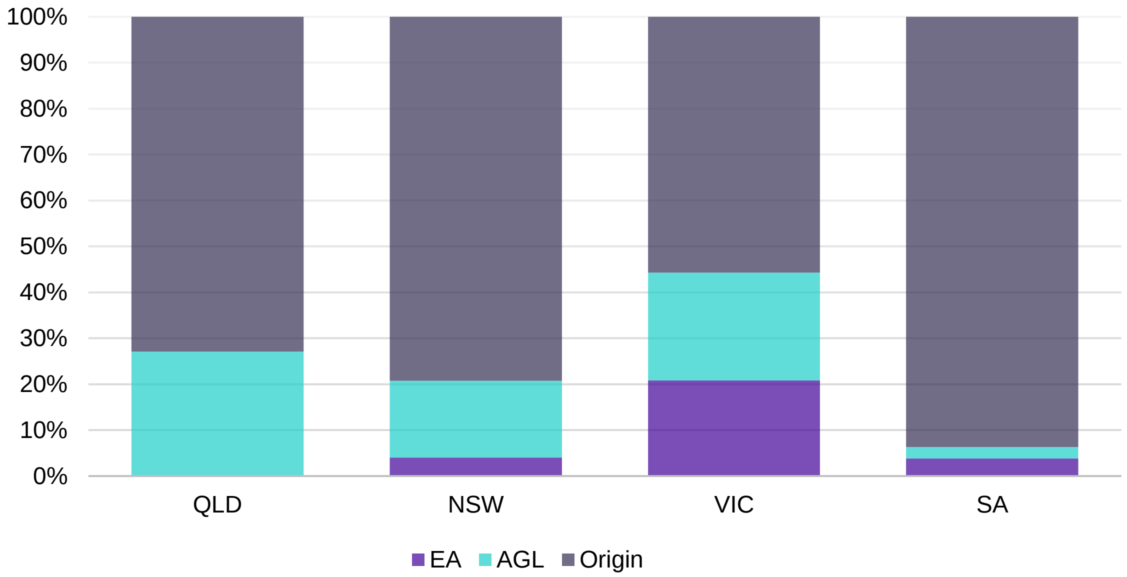


Source: AER, Retail energy market performance report, December 2018; ESC, Victorian energy market report 2016-17, November 2017

4.3.2. C&I customers

In 2018, the major retailers supplied lower volumes of gas to all C&I customers (see section 4.4.1 below for a definition of C&I customers) than in previous years. As discussed further in section 4.5.4, AGL and EnergyAustralia have significantly reduced the amount of gas supplied to these C&I customers, while Origin has slightly increased its C&I supply. Chart 4.2 below shows the shares of C&I market volumes supplied by the major retailers in each state for 2018.

Chart 4.2: C&I volumes supplied by major retailers in 2018, PJ



Source: ACCC analysis of information provided by retailers

4.4. Analytical approach

This section sets out the approach the ACCC has taken to collect information from each of the retailers to analyse their pricing, costs and margins.

Section 4.4.1 below explains the information collected for our analysis, while section 4.4.2 outlines the method we have used to understand costs and margins on a disaggregated level (that is, by state and by type of customer supplied). Finally, section 4.4.3 discusses the 'cost stacks' we have used to present our findings and how these should be interpreted.

4.4.1. Information collected from retailers

The ACCC used its compulsory information gathering powers to obtain information about the retailers' gas supply businesses for the analysis of retailer prices, costs and margins in this chapter.[131] Information collected included:

- 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 4.1 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).

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

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

information relating to internal transactions within the retailers' overall businesses. The ACCC sought information that did not derive from transfer prices, except when no other information existed.[132] We note, however, that where cost information has been provided in relation to a retailer's own gas production, it has been provided on the basis of transfer prices rather than the cost of production.

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 to determining customer types are similar.

This has allowed for the grouping of various customer type information into four separate groups that are broadly consistent across the retailers:

- Mass market customers—made up of both residential and small to medium sized enterprise 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. Depending on the location of these customers, they may receive their supply via a distribution network or directly from a transmission pipeline. The bulk of all C&I customers are in this group, however some retailers have categorised a small number of C&I users as wholesale customers.
- Wholesale customers—this category includes supply to other retailers, the LNG projects, gas powered generators (GPG), and a number of other major gas users. Typically these customers are connected to a transmission pipeline and consume more than 1 PJ per year. A small number of users characterised in other parts of this report as 'C&I' may be treated by the retailers as wholesale customers.
- The retailers' own GPGs.

For the pricing analysis in chapter 2, the ACCC collects contracts and offers for gas supply to C&I users that have an annual contract quantity of more than 0.5 PJ per year. We have reported on this over the course of the Gas Inquiry. In contrast, the C&I customer category used for the analysis in this chapter includes customers that have an annual contract quantity of more than 1 TJ per year and excludes a small number of C&I users that retailers classify as wholesale customers.

Accordingly, some of the analysis in this chapter, which is based on contract and offer volumes and prices, informs our assessment of retailers supply of gas to C&I users, but a direct comparison or conclusion cannot always be made.

Box 4.1: Components of retailer 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.

[132] 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.

Pipeline costs reflect the costs of transporting gas on both transmission pipelines[133] and distribution networks[134] 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.

4.4.2. Cost allocation

During 2018, we engaged with the retailers on the most appropriate way to collect revenue, volume and cost information for the purpose of our analysis. While the ACCC has obtained revenue and volume information from the retailers that is disaggregated by state and customer type, cost information has generally been provided on a whole of east coast basis. The retailers have explained that they are not able to provide disaggregated cost information because they incur costs and supply gas on a portfolio basis, and that as a result, costs cannot reliably be attributed to particular locations and customer types.

To estimate the retailers' costs and margins for each state and customer type, we have used a range of cost and volume information provided by the retailers to allocate the various cost types at this level. The method we have used to allocate costs to states and customer types are as follows:

- Commodity costs—Given that the retailers acquire gas across the east coast on a portfolio basis, gas commodity costs are averaged across states and customer types. This means that each retailer's commodity costs are assumed to be the same across all states and customer types, except where adjustments are made to reflect the costs associated with satisfying peak demand of different customer types.
- Distribution costs—The retailers have provided distribution costs per state. State costs are allocated to mass market and C&I customer types on the basis of data obtained from retailers on the costs incurred for 'residential' and 'industrial' distribution network tariff classes.
- Transmission costs—The retailers have provided transmission costs for the Victorian Transmission System (VTS). Costs for other states are allocated using data obtained from the retailers on interstate pipeline flows and pipeline costs. State costs are allocated to customer types based on volumes supplied, except where adjustments are made to reflect the costs associated with satisfying peak demand of different customer types.
- Retail costs—These costs are allocated to mass market and C&I customers using data on the number of these customers in each state. We assume that retail costs are spread evenly across these customers.
- Other costs—Given that these costs are incidental to the retailers' purchase of gas commodity, we use the same allocation approach and average the costs across states and customer types.

[133] 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.

[134] Distribution pipelines, on the other hand, transport gas at a lower pressure from the city gate to commercial and residential customers.

Before finalising the method used to allocate costs and estimate margins for this report, we consulted with each of the major retailers and provided them with draft cost stacks using their respective data. We have made adjustments to some cost allocations based on retailer responses where we considered it appropriate and where the retailers were able to provide robust and reliable data. The adjustments were generally made to more accurately reflect the additional costs incurred by the retailers in satisfying peak demand for mass market customers, particularly in the southern states, relative to other customer types.

4.4.3. Cost stack analysis

The ACCC's analysis of the retailers' costs and margins is presented in this report using 'cost stacks' that show delivered prices, costs components and resulting margins averaged across the three major retailers.

Each cost stack is derived by taking average delivered prices for each state and customer type and subtracting allocated costs. The delivered prices are calculated by dividing revenues by volumes supplied, which the retailers have provided on a per-location and customer type basis. Costs are allocated using the approach outlined above, and subtracted from delivered prices to estimate margins.

While the ACCC's findings on retailer costs and margins in this report are derived entirely using data obtained directly from the retailers, there are some caveats that should be kept in mind when interpreting the results:

- The cost stacks show the estimated margins actually realised in each year averaged across all volumes supplied (as distinct from the margins that the retailers expected to earn when entering into a particular contract). They reflect all costs incurred and revenues received in respect of gas supply in that year. This includes both costs incurred and revenues received under contracts executed at different points in time prior to the supply year for which margins are calculated. This means that the costs and revenues used to calculate the margins can reflect market dynamics at different points in time.
- The delivered prices and margins shown in the cost stacks are based on revenues received under all contracts on foot in a given year. Each year, some older contracts expire while new contracts commence. For C&I users in particular, given that many older and lower priced contracts have rolled off in recent years, and given recent increases in wholesale prices and the trend towards shorter term contracts, the C&I cost stacks for each year will become more reflective of recent market dynamics.
- As discussed above, the retailers operate the gas supply segments of their businesses on a portfolio basis and as such have not provided costs disaggregated by location and customer type. While we have allocated the retailers' costs using what we consider to be the most appropriate method in consultation with the retailers, the allocations are ultimately notional and the results are therefore indicative.
- Customer types include customers with a wide range of usage profiles. For example, mass market includes residential and small business customers with usage up to around 1 TJ per year, while C&I includes both small and large users with annual usage of more than 1 TJ (see detailed explanation in section 4.4.1). The prices and margins across each customer group are likely to have at least some degree of variation and the prices and margins shown in this chapter therefore do not represent those paid by a 'typical' customer, but rather an average across a wide range of customers.
- Related to the above point, any change in the mix of volumes supplied by the retailers to small and large C&I users may influence average prices and margins, to the extent that the prices paid by these types of C&I user, and the costs incurred by the retailers to supply them, are different.

As noted above, while the ACCC has obtained data from the retailers in the most standardised way possible, in some cases this has required the retailers to give information in a form they would not normally keep it. In particular, for wholesale customers and the retailers' own GPGs, some retailers have developed methodologies to allocate revenues and volumes to different states where they have said they consider them on a whole of east coast basis. In addition, some of the revenue information provided by the retailers, particularly for their own GPGs, is based on internal transfer prices which may not be reflective of market prices. For these reasons, the ACCC has not included cost stacks for wholesale customers and the retailers' GPGs in this report.

4.5. Average retailer prices and estimated margins

The ACCC's findings on retailer costs and margins as reported in December 2018 were presented at an aggregate level for the major retailers across the East Coast Gas Market and across all customer types. For this report, we have extended our analysis to include 2018 data collected from the retailers, and analysed the costs and margins of the retailers at a state level and for each customer type.

We have found that average margins across the retailers for mass market and C&I gas customers are high. Margins are significantly higher than previously established benchmarks for reasonable retail gas margins in the east coast market (such as those used in past regulatory decisions—see section 4.5.1). Further, our analysis shows that margins vary widely between states and between individual retailers. While some of this variation is due to differences in delivered prices across states, it is also because the retailers' cost of supply varies between states.

Section 4.5.1 discusses measures of retail margins in gas markets that the ACCC has used to compare to the margins found in this analysis. Section 4.5.2 and 4.5.3 present the results of our analysis and discuss our findings.

Box 4.2 below discusses the publicly available information on retailer margins that has been reported in recent years, including by the retailers as well as by independent reviews, and explains how the findings presented in this report differ.

Box 4.2: Other reporting on retail gas margins

Publicly available information on retail gas margins in the East Coast Gas Market is limited. While the major retailers do include some information on retail margins in statutory reports and information provided to shareholders, they are often reported on an energy portfolio basis (that is, across gas and electricity) or at an aggregate level across all locations and types of customer.

Further, depending on the retailer, reporting can vary between measures of margin such as gross margin, EBITDA and EBIT. Therefore, using the information published by the retailers it is not possible to reliably gain insight into revenues, costs and margins for different locations within the East Coast Gas Market and for the various market segments.

Another source of information on gas retailer costs and margins is reviews conducted by and for regulatory agencies and government bodies. One of the most recent is Oakley Greenwood's Gas Price Trends Review 2017 report commissioned by the Department of the Environment and Energy for the COAG Energy Council.[135] This report estimates delivered gas prices paid by residential customers, as well as both small and large C&I customers at a jurisdictional level across Australia. It also estimates breakdowns of delivered prices into commodity, transmission, distribution and retail cost and margin components, where relevant depending on the type of customer.

Oakley Greenwood found that wholesale gas commodity prices agreed in new GSAs in the East Coast Gas Market began gradually increasing from historical levels of $3–4/GJ around 2009–10, and

135 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018

had increased to around $8–9/GJ by 2015–16.[136] The report found that delivered prices for both residential and C&I customers had similarly increased. While the report did not make a finding on margins included in delivered prices paid by C&I users, it found that retail costs and margins collectively made up 25 per cent of delivered prices for residential customers in 2017.[137]

Oakley Greenwood's analysis is based on a range of information sources including samples of contracts executed between industrial customers and suppliers, published transmission and distribution tariffs across jurisdictions, and retailers' market offer information. Importantly, the report's findings on the commodity cost component of both residential and industrial customer bills are based on the wholesale gas component of large industrial customer contracts with suppliers, executed in the year in question.[138] As noted by Oakley Greenwood in its report, given that most retailers' gas supply portfolios include gas under relatively low priced legacy contracts, it is likely that actual retailer wholesale gas costs are lower than what is estimated in the report.[139]

In addition, given that commodity costs are based on the wholesale component of contracts with industrial users, the report does not distinguish between the wholesale gas price agreed by users and the actual cost of gas to a supplier at the wholesale level. As a result, the report's findings on margins included in delivered prices for residential customers do not appear to include margins received by suppliers on the commodity component. However, as noted above, Oakley Greenwood's report does show the long-term trend of increasing prices in new gas supply agreements across the East Coast Gas Market—starting with a gradual increase from around 2010 and leading to significant increases, particularly in southern states, between 2015 and 2016.

The ACCC's analysis presented in this report addresses the limitations mentioned above. As discussed in section 4.4, the ACCC has used its compulsory information gathering powers to obtain comprehensive revenue, cost and volume information from the major retailers in a standardised format that allows as much as possible for like comparisons between retailers. This data reflects revenues received, costs incurred and volume supplied under all types of supply arrangements, regardless of the date of execution. Using other cost and portfolio data obtained from the retailers, and applying the methodology described above to allocate the retailers' costs to individual states and customer types, allows for the estimation of EBITDA margins that are comparable across the retailers.

4.5.1. Measures of retail margins used for comparison

As discussed above, we have used EBITDA as the measure of retail gas margins presented in this report. These margins therefore account for profits after cost of goods sold (that is, commodity, distribution, transmission and other costs) and retail operating costs are deducted, but do not include an allowance for a return on capital. To the extent that these costs are significant, a margin that accounts for this (such as EBIT) would be lower, however the ACCC has not conducted an assessment of an appropriate return on capital for this report. The ACCC has had regard to the most recent regulatory determination which has included an assessment of what is a 'reasonable' EBITDA margin for retail gas supply.

While retail gas markets have become progressively deregulated over the past decade, the last state in the east coast market to have prices subject to regulatory assessment was NSW for the 2016–17 financial year. In June 2016, IPART issued a final determination on regulated retail gas prices that could be charged by applicable gas retailers for residential and small business customers in NSW during this regulatory period. This included an assessment of a reasonable retail margin that would compensate retailers for the systematic risks associated with supplying small gas customers on regulated tariffs.[140] For this assessment, IPART had regard to independent analysis which estimated a reasonable EBITDA range that would be consistent with the costs an efficient and prudent retailer would incur in a competitive market.[141]

136 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 84.
137 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 20.
138 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 241.
139 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 241.
140 IPART, *Review of regulated retail prices and charges for gas from 1 July 2016*, June 2016, p. 41.
141 SFG Consulting, *Estimation of a competitive profit margin for gas retailers in New South Wales*, April 2010, p. 1.

In its final determination, IPART used an EBITDA range of 6.3 to 7.3 per cent, based on the independent analysis, to assess the pricing proposals of the retailers.[142] Further, the analysis used by IPART included an examination of comparable margins used by regulators in other jurisdictions and found that, with the exception of South Australia, they were generally at the lower end of this range.[143]

Further, in the ACCC's Retail Electricity Pricing Inquiry (REPI) final report, the ACCC found that average EBITDA margins across the NEM in 2017–18 for residential and small to medium enterprise electricity customers—equivalent to the mass market category used in this report—were both 8 per cent, and that margins for C&I customers were 2 per cent. We note, however, that the method for estimating wholesale costs in that report is slightly different to the method used for estimating commodity gas costs for the purpose of this report. The REPI report derived wholesale costs on the basis of the costs reported by businesses, which for some retailers included costs of 'acquiring' electricity based on internal transfer prices. In contrast, the commodity gas costs used to estimate margins for this report are based on actual costs incurred (with the exception of costs associated with the retailers' own gas production, as noted in section 4.4.1 above).

To the extent that the ACCC has commented on the level of retailer margins observed in our analysis for this report, we have had regard to the reasonable EBITDA range used by IPART in its 2016 determination and the margins found in the ACCC's REPI report. The ACCC notes, however, that IPART's range was determined for the purpose of determining retail gas charges for small gas customers. Where the ACCC has had regard to any additional costs or risks faced by the retailers in supplying gas to C&I customers, this is noted in the sections below.

4.5.2. Average delivered prices and margins for mass market and C&I gas customers are high across the East Coast Gas Market

This section presents the average prices and estimated margins for mass market and C&I customers. As noted above, these categories include customers with a wide range of usage profiles: mass market includes residential and small business customers with usage up to around 1 TJ per year, while C&I includes users with annual usage of more than 1 TJ and many C&I users with a substantially higher annual usage. Within the C&I category there are two broad types of C&I user:

- Large C&I users with an annual usage of around 100 TJ or more, and
- Small C&I users with annual loads below this level.

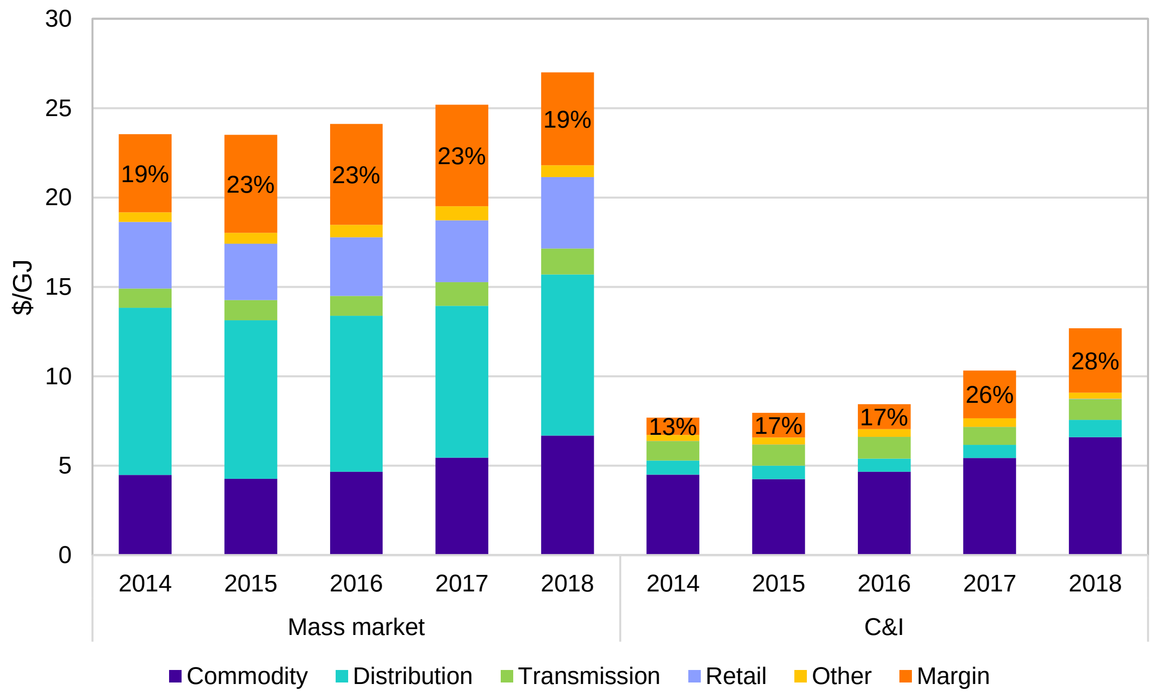
While larger C&I customers may be able to purchase gas either on a delivered basis from retailers or acquire gas at the wholesale level and arrange their own transportation, smaller C&I users may not have this option. Producers generally do not supply gas to customers with low annual usage, and these smaller C&I users may not be able to engage with pipeline operators to acquire the pipeline capacity necessary to have gas delivered to their location (either because of their small capacity requirements or because they do not have the internal capacity to manage the complexity of gas transportation arrangements).

Given that both types of user make up the C&I category used in this analysis, the prices and margins shown here do not represent those paid by a 'typical' customer, but rather an average across a wide range of customers. The implications of the ACCC's findings on retailer pricing and margins for different types of C&I users are discussed in section 4.5.4 below.

142 IPART, *Review of regulated retail prices and charges for gas from 1 July 2016*, June 2016, p. 41.
143 SFG Consulting, *Estimation of a competitive profit margin for gas retailers in New South Wales*, April 2010, p. 7.

Chart 4.3 below shows average prices paid and estimated margins for mass market and C&I customers across the whole East Coast Gas Market.

Chart 4.3: Cost stacks for whole East Coast Gas Market, mass market and C&I



Source: ACCC analysis of information provided by the major retailers

Note: Costs are allocated to the mass market and C&I customer segments, and margins are estimated, based on the methodology outlined in section 4.4.2 above. See section 4.4.3 for caveats in relation to these estimates.

Chart 4.3 shows that delivered prices on average across the east coast have increased for both mass market and C&I customers over the period from 2014 to 2018. As discussed previously, this period covers part of the East Coast Gas Market's shift to a pricing dynamic that is shaped by relatively high international LNG prices and the rising cost of domestic gas production. Over time, prices paid by domestic retail gas customers would be expected to rise with the increase in wholesale commodity gas prices. The increase in average prices across the market shown in chart 4.3 reflects this.

However, while chart 4.3 shows that the retailers' overall cost of gas supply has increased in each year since 2015, mainly driven by the retailers' average portfolio commodity costs, they have not increased as much as average prices. Average commodity costs increased from about $4/GJ in 2015 to around $6.50/GJ in 2018, reflecting the trend of increasing commodity costs for the retailers as relatively low-priced legacy contracts with producers roll off and more recent and higher-priced contracts make up a larger portion of their portfolios.

This is expected to continue. As shown in the ACCC's April 2019 Interim report, the average gas commodity price paid to producers under all contracts over 2018 was similarly around $6.50/GJ, while the average price paid under contracts executed since the start of 2017—including those with the major retailers—was between around $8.50 to $9/GJ.[144] This suggests that the retailers' commodity costs will continue to increase further over time and lead to an overall increase in the cost of supplying all types of customers.

[144] ACCC, *Gas Inquiry 2017-2020—Interim report*, April 2019, p. 41.

Chart 4.3 shows that average delivered prices for mass market customers have increased commensurately with commodity gas costs while other cost components have remained stable. As a result, average margins for mass market customers across the East Coast Gas Market have remained relatively steady, fluctuating between 19 and 23 per cent over the period.

In contrast, average delivered prices for C&I customers have increased more than the retailers' average cost of supply, leading to an increase in average margins. Average margins for C&I customers have increased from 13 per cent in 2014 to 28 per cent in 2018.

These margins for east coast mass market and C&I gas customers contrast with the retail electricity margins found in the ACCC's Retail Electricity Pricing Inquiry final report. In that report, the ACCC found that margins across the NEM in 2017–18 for residential and small to medium enterprise electricity customers—equivalent to the mass market category used in this report—were both 8 per cent, and that margins for C&I customers were 2 per cent.[145] As shown in chart 4.3 above, margins across the East Coast Gas Market for mass market and C&I customers in 2018 were 19 and 28 per cent, respectively.[146] We discuss developments in both customer segments in section 4.5.4 below.

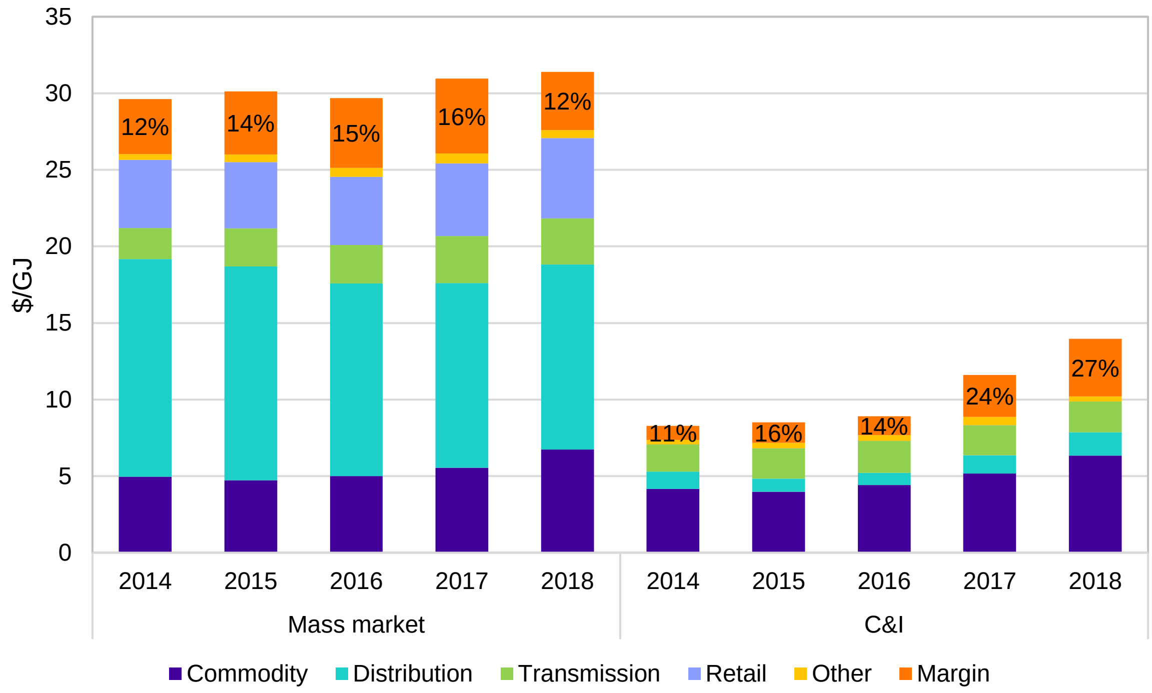
4.5.3. Average prices and margins have varied widely across states and between retailers

Chart 4.3 above shows the extent to which average delivered prices, costs and margins differ between mass market and C&I customers across the east coast. Our analysis has also shown that prices, costs and margins vary considerably between states and between retailers within states. This is shown in the charts below.

145 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry final report*, June 2018, p. 30.

146 As noted in section 4.5.1, the REPI report derived wholesale costs on the basis of the costs reported by businesses, which for some retailers included costs of 'acquiring' electricity based on internal transfer prices. In contrast, the commodity gas costs used to estimate margins for this report are based on actual costs incurred (with the exception of costs associated with the retailers' own gas production, as noted in section 4.4.1 above).

Chart 4.4: Cost stacks for New South Wales, mass market and C&I



Source: ACCC analysis of information provided by the major retailers

Note: Costs are allocated to the mass market and C&I customer segments, and margins are estimated, based on the methodology outlined in section 4.4.2 above. See section 4.4.3 for caveats in relation to these estimates.

Chart 4.4 shows that average delivered prices for C&I customers in NSW broadly align with the east coast averages shown in chart 4.3, while delivered prices for NSW mass market customers are higher. Despite this, average margins for both C&I and mass market customers in NSW are lower than the east coast average.

This is likely because of the higher cost of supplying customers in NSW. NSW produces little gas relative to other parts of the east coast, and mostly relies on gas imports to meet demand.[147] Most of NSW's gas is imported via transmission pipelines, such as from Victoria via the Eastern Gas Pipeline (and to a lesser extent, the Victoria-NSW interconnect), from South Australia via the Moomba to Sydney Pipeline, and increasingly from Queensland via the South West Queensland Pipeline and Moomba to Sydney Pipeline.[148] The cost to retailers of transporting gas to NSW via these pipelines leads to a high per gigajoule cost of transmission when averaged across NSW customers.

Chart 4.4 shows that average delivered prices and margins for NSW mass market customers have remained relatively stable over the period, with margins between 12 and 16 per cent over the period. This is despite the general increase in commodity costs across the east coast, which appears to have been offset to an extent by a fall in per gigajoule distribution costs in NSW, likely the result of an AER determination for Jemena Gas Networks in Sydney which lowered distribution charges for the 2015–2020 regulatory period.

C&I customers in NSW, on the other hand, have experienced an increase in delivered prices which has been greater than the rate of increase in the retailers' cost of supply. As a result, average margins for C&I customers in NSW have increased, from between 11 and 16 per cent over 2014–16, to between 24 and 27 per cent in 2017 and 2018.

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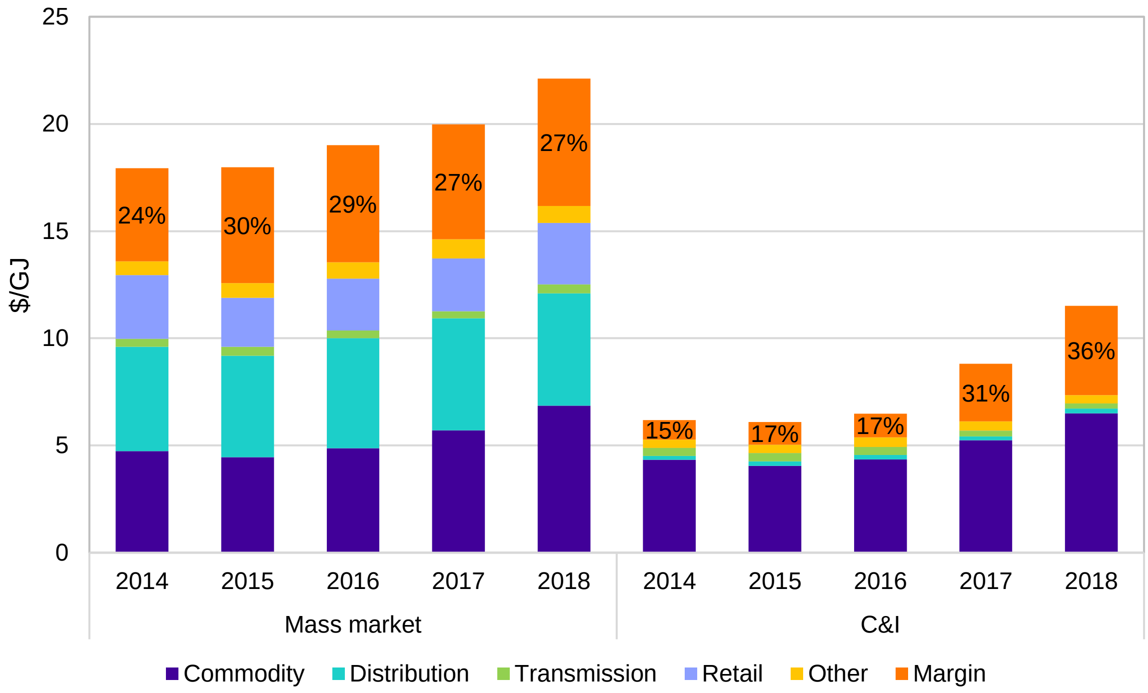
147 AER, *State of the Energy Market 2018*, p. 208.
148 EnergyQuest, *EnergyQuarterly*, September 2018, p. 22.

Chart 4.5: Cost stacks for Victoria, mass market and C&I



Source: ACCC analysis of information provided by the major retailers

Note: Costs are allocated to the mass market and C&I customer segments, and margins are estimated, based on the methodology outlined in section 4.4.2 above. See section 4.4.3 for caveats in relation to these estimates.

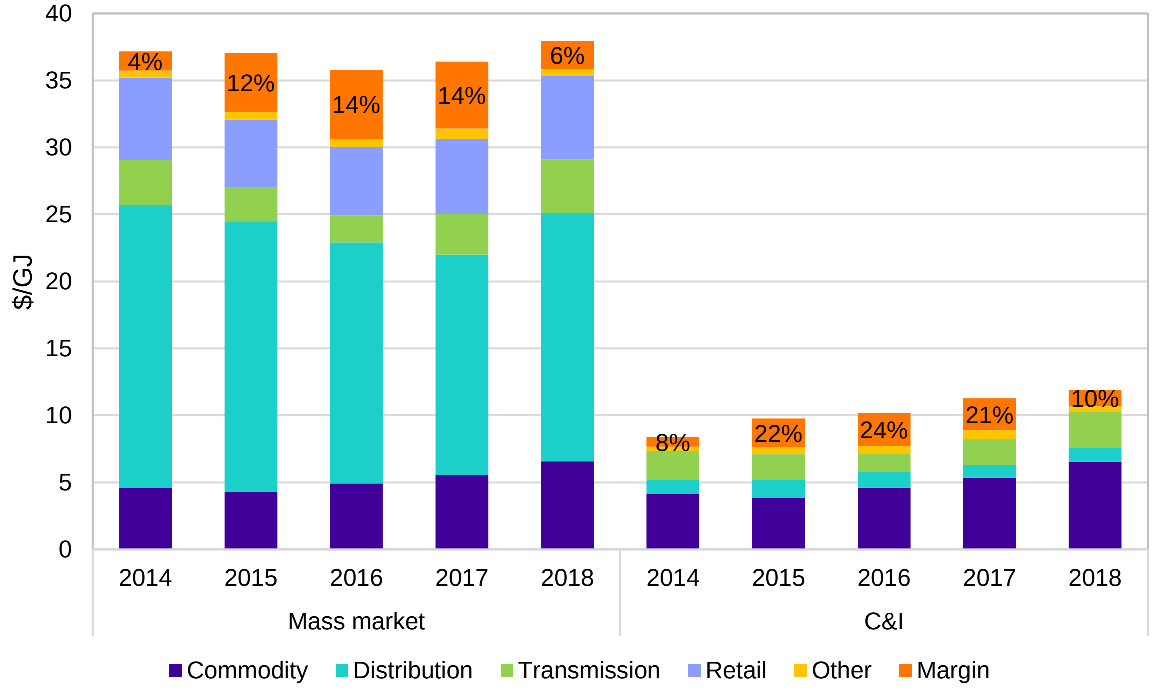
Chart 4.5 shows that average delivered prices for mass market customers in Victoria have risen in line with the increase in commodity costs, leading to margins remaining relatively stable at between 24 and 30 per cent.

Chart 4.5 also shows that average delivered prices for Victorian C&I customers have increased at a greater rate than average costs. Between 2015 and 2018, while most costs remained stable, commodity costs increased by around 60 per cent. In contrast, over the same period, average delivered prices paid by Victorian C&I customers increased by almost 90 per cent. As a result, average margins for Victorian C&I customers have risen substantially, from between 15 and 17 per cent over 2014–16 to 31 and 36 per cent in 2017 and 2018, respectively.

However, while the Victorian C&I margins shown in chart 4.5 above are clearly significant, it is important to note that they are averaged across the retailers. There has been a wide range of margins earned by the retailers in Victoria. For example, margins for Victorian C&I customers for one of the retailers were below 10 per cent from 2014 to 2017 and around 16 per cent in 2018. For another retailer, Victorian C&I margins averaged around 22 per cent from 2014 to 2016 and increased to more than 40 per cent in each of 2017 and 2018.

A key feature of the cost stacks for Victoria shown in chart 4.5 above is the level of delivered prices and the cost of supply when compared to the east coast averages shown in chart 4.3 and the cost stacks for other states in this section. This comparison shows that average delivered prices and average costs of supply for both mass market and C&I customers in Victoria are the lowest across the East Coast Gas Market. The lower cost of supply is likely due to Victoria's gas demand being able to be met by local sources of production, which reduces the need for gas to be transported over long distances, as well as the relatively low cost of transmission within the VTS and distribution networks (all of which are fully regulated). At the same time, however, average margins for Victorian mass market customers are the highest across the east coast, and average margins for C&I customers are among the highest, particularly in 2017 and 2018.

Chart 4.6: Cost stacks for South Australia, mass market and C&I



Source: ACCC analysis of information provided by the major retailers

Note: Costs are allocated to the mass market and C&I customer segments, and margins are estimated, based on the methodology outlined in section 4.4.2 above. See section 4.4.3 for caveats in relation to these estimates.

Chart 4.6 shows that average delivered prices have been flatter over the period in South Australia than in NSW and Victoria. Delivered prices for mass market customers have been relatively stable, while delivered prices for C&I customers have increased, but at a lower rate than in NSW or Victoria.

With average delivered prices for mass market customers in South Australia remaining relatively constant over the period, and the average cost of supplying these customers fluctuating, this has caused margins to rise and fall, with an increase from 4 per cent in 2014 to 14 per cent in 2016, then a decrease to 6 per cent in 2018.

With the average cost of supplying South Australian C&I customers increasing in each year since 2016, but at a lower rate than delivered prices, margins for these customers have decreased, from 24 per cent in 2016 to 10 per cent in 2018.

As is the case for Victoria, there has been a wide range of margins earned by the retailers in South Australia. For example, margins for South Australian C&I customers for one of the retailers were mostly either around zero or negative over the period. For another retailer, South Australian C&I margins averaged around 25 per cent over the period and were as high as 33 per cent in 2017.

The increase in the average cost of supply in South Australia over the past few years has been off an already high base relative to the east coast average, and Victoria in particular. This is likely because, similar to NSW, retailers incur costs to transport gas to the main sources of demand, in particular via the SEAGas pipeline and the Moomba to Adelaide

Pipeline System. The cost to retailers of transporting gas via these pipelines leads to a high per gigajoule cost of transmission when averaged across South Australian customers.

Average prices, costs and margins in Queensland

The ACCC notes that we have not included detailed cost stacks for Queensland in this report, since these are aggregated across only two of the major retailers and would potentially disclose confidential information. However, we provide general commentary on average prices, costs and margins in Queensland below.

Average delivered prices for both mass market and C&I customers in Queensland have been the highest across the East Coast Gas Market in every year from 2014 to 2018. Average delivered prices for mass market customers have increased over the period broadly in line with commodity costs, with an average of around $42/GJ over the period. Total cost of supply averaged around $32/GJ over the period. Average margins have mostly been stable, averaging around 24 per cent over the period.

For Queensland C&I customers, average delivered prices were mostly stable between 2014 and 2018, averaging around $13/GJ over this period, while total cost of supply for C&I customers averaged around $9/GJ.

Because of the high level of average delivered prices for C&I customers in Queensland relative to the cost of supply, average Queensland C&I margins are the highest anywhere on the east coast, with an average of 34 per cent over the period. However, given that delivered prices for these customers have remained relatively constant over the period, the increase in average commodity costs has led to a decline in these margins.

For both mass market and C&I customers, the average cost of supply in Queensland is among the highest across the East Coast Gas Market, despite much of the state's gas demand being met by local sources of production. This appears to be due to distribution charges in Queensland, which are relatively higher than other states. This is likely due to the nature of demand in Brisbane, where gas customers generally have much lower usage profiles than other states, leading to distribution network operators incurring higher average costs. However, as noted above, because of the high level of delivered prices for both mass market and C&I customers, margins in Queensland are also among the highest across the market.

4.5.4. High margins are at least partly a function of lower cost supply in the south and broader market supply-demand dynamics

The cost stacks above show that while margins for mass market and C&I customers have varied widely across states and between individual retailers, they have generally been high. With few exceptions, average retailer margins across the market over the period from 2014 to 2018 have been well in excess of the retail electricity margins found by the ACCC's Retail Electricity Pricing Inquiry and the reasonable EBITDA margin range used by IPART for residential gas customers in NSW.[149] In Victoria and Queensland in particular, most margins generated by the retailers from mass market and C&I customers have been multiples of these comparators.

The retailers' average cost of supply has increased over the period, mostly driven by the increase in commodity gas costs experienced by all gas market participants. Average delivered prices for mass market customers have generally risen in line with commodity costs, but for C&I customers in most states, delivered prices have increased at a greater

[149] As noted in section 4.5.1, the REPI report derived wholesale costs on the basis of the costs reported by businesses, which for some retailers included costs of 'acquiring' electricity based on internal transfer prices. In contrast, the commodity gas costs used to estimate margins for this report are based on actual costs incurred (with the exception of costs associated with the retailers' own gas production, as noted in section 4.4.1 above).

rate, resulting in higher margins. While margins for mass market customers are high, they have been maintained at this level for the full period we have analysed. Margins for C&I customers, on the other hand, have increased significantly only in the past few years. There are some indications that this increase may be transitory, although further monitoring and examination is necessary.

The sections below discuss the retailers' pricing, costs and margins for mass market and C&I customers in further detail.

Mass market margins have been high over the past five years

Margins for mass market customers have been high for the full five year period we have analysed for this report. As discussed above, while there has been some variation across states and between retailers, retailer margins across the east coast for mass market customers have averaged between 19 and 23 per cent from 2014 to 2018. Unlike those estimated for C&I customers, these margins have remained relatively constant over the period as delivered prices have increased generally in line with the increase in commodity costs, while other cost components have not moved significantly.

As noted above, these margins contrast with the ACCC's previous findings on retail electricity margins, which were found to be 8 per cent for both residential and small to medium enterprise customers in 2017–18.[150] The ACCC's Retail Electricity Pricing Inquiry final report in June 2018 identified several factors that had adversely affected consumer outcomes in retail electricity markets over the previous decade. These included the significant advantages of retail market incumbency enjoyed by the major retailers, as well as a high level of consumer disengagement resulting in large parts of the retailers' customer base remaining on highly-priced offers.[151] In this environment, incumbent retailers have focused their efforts on retaining profitable customers, while new entrants and smaller retailers compete only for the 'active' part of the market.[152]

The ACCC has not conducted a formal assessment of the state of competition in the retail gas market. However, there is some evidence to suggest that factors such as these may also be leading to adverse outcomes for mass market gas consumers.

The retail gas market is even more concentrated than the electricity market, with the major retailers supplying around 75 per cent of small gas customers across all parts of the east coast market (compared to 68 per cent of electricity customers across the NEM).[153] While it appears that retail competition is developing across the market, it appears to be most developed in Victoria, where smaller retailers are now supplying about a third of customers.[154] However, as shown in chart 4.5 above, average margins for the major retailers for mass market customers in Victoria have been consistently higher, and average delivered prices have risen at a faster rate, than in any other state over recent years.

Between 2014 and 2018, around 60 per cent of all gas supplied to mass market customers by major retailers was supplied in Victoria. Data collected by the AER shows that in Victoria there is a higher proportion of small gas customers on market offers—which are generally priced lower than standing offers—than in any other state.[155] However, the range of annual bill costs under market contracts is very large in Victoria when compared to other

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150 As noted in section 4.5.1, the REPI report derived wholesale costs on the basis of the costs reported by businesses, which for some retailers included costs of 'acquiring' electricity based on internal transfer prices. In contrast, the commodity gas costs used to estimate margins for this report are based on actual costs incurred (with the exception of costs associated with the retailers' own gas production, as noted in section 4.4.1 above).

151 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry final report*, June 2018, p. xi.

152 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry final report*, June 2018, p. xi.

153 AER, *State of the Energy Market 2018*, p. 46.

154 AER, *State of the Energy Market 2018*, p. 46.

155 AER, *State of the Energy Market 2018*, p. 51.

jurisdictions, indicating that there is potential for customers to achieve significant savings when switching between retailers.[156]

Further, as in retail electricity markets, there appears to be a similar emphasis by the retailers on the retention of more profitable gas customers. In one of the retailers' internal board documents collected by the ACCC for this inquiry, it characterised the potential transition of its energy customers (both electricity and gas) on 'non-discounted' products to 'discounted' products arising from retail competition as a 'risk'. This retailer noted that, while it regarded competition from other major retailers as 'intense' in some parts of the market, and had seen an increase in the proportion of its customers on discounted products, it had implemented a strategy 'not to lead on price' and was pursuing 'alternative retention and acquisition strategies'. Similarly, another retailer noted in an internal board document that it would be preferable not to aim for an additional level of customer growth across its broader energy portfolio 'that would lead to strong competitor reaction in the market, and value destruction through even more aggressive discounting'.

As mentioned above, the ACCC has previously found that the high level of consumer disengagement in electricity has resulted in many retail customers remaining on highly-priced offers. The AEMC has found that, over recent years, gas has been considered a secondary product to electricity rather than a stand-alone service, with many retail energy customers having a preference for dual fuel retail offers from a single retailer.[157] The ACCC considers that consumer disengagement in the retail energy market more generally, coupled with the tendency for gas to be seen as a secondary product, may be contributing to the high margins being generated by the retailers from mass market gas customers.

The AEMC found in 2018 that energy market competition has not yet evolved in a way that is delivering desired outcomes for consumers, and that the common use of 'discounts' for both electricity and gas has created a confusing and complicated environment.[158] The ACCC's Retail Electricity Pricing Inquiry found the practice of discounting to be problematic because they are set by each retailer using the retailer's own reference price, meaning that there is no easy way for consumers to compare discounts between retailers.[159] To address this, the ACCC recommended that retailer discounting for electricity market offers should be made with reference to a 'default market offer' that would be determined by the AER.[160] In April 2019, the AER issued a final determination on Default Market Offer prices based on this recommendation.[161]

The ACCC considers that these issues—market concentration and consumer disengagement—may be contributing to the high level of average prices being paid by mass market gas customers relative to the major retailers' average cost of supply. The ACCC will undertake further monitoring and analysis of the retail gas market to better understand the drivers of retail margins in this market segment.

156 AER, *State of the Energy Market 2018*, p. 58.
157 AEMC, *2019 Retail Energy Competition Review: Final Report*, June 2019, p. vi.
158 AEMC, *2018 Retail Energy Competition Review: Final Report*, June 2018, p. v.
159 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry final report*, June 2018, p. xi.
160 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry final report*, June 2018, p. xiii.
161 AER, 'AER issues Default Market Offer decision,' April 2019, https://www.aer.gov.au/news-release/aer-issues-default-market-offer-decision.

Margins for small and large C&I customers have increased over recent years

As explained previously, our examination of gas supply agreements and offers, as well as the interviews we have conducted with C&I users, indicate that there are two broad types of C&I customer:

- Large C&I users (with an annual usage of around 100 TJ or more) who are generally able to acquire gas at the wholesale level from producers or retailers and arrange their own transportation (if necessary), and
- Small C&I users with loads below this level who generally rely on retailers to deliver gas to their location.

Given that both types of user make up the C&I category used in this analysis, the prices and margins are likely to have at least some degree of variation across the category and the prices and margins shown here do not represent those paid by a 'typical' customer, but rather an average across a wide range of customers.

As shown in the charts above, average prices paid to the major retailers by this broad group of C&I users have been increasing across the East Coast Gas Market between 2014 and 2018. The increase has been particularly pronounced in NSW and Victoria, where between 70 and 80 per cent of C&I customer volumes were supplied by the major retailers in each year over this period. Between 2016 and 2018, average prices in NSW increased by 57 per cent between, while in Victoria average prices increased by 77 per cent. In South Australia, average delivered prices have generally risen in line with commodity costs, while in Queensland, average delivered prices have been relatively stable since 2015.

The increase in average prices paid by C&I customers across the east coast—and particularly in the southern states—is consistent with the ACCC's previous findings on the increase in average commodity gas prices paid to all retailers by C&I users with annual contract quantities of at least 0.5 PJ. As discussed in previous reports, domestic gas prices in recent years have been shaped by LNG netback prices and supply-demand dynamics, particularly the tight supply conditions in the southern states (see section 1.4). As market pricing dynamics have transitioned to being influenced by these factors, wholesale gas prices have risen. With LNG netback prices being high relative to historical domestic gas prices, and supply and demand conditions having worsened in 2016 and 2017, the East Coast Gas Market has gradually seen domestic gas commodity prices increase from levels of around $3–4/GJ to around $10/GJ (and higher for retailers).

While the retailers have been similarly exposed to increasing wholesale market prices when seeking to enter into new supply contracts over recent years, their gas supply portfolios still include significant quantities under a range of long-term and relatively low-priced legacy contracts with producers. The low prices paid by the retailers under these legacy contracts have the effect of lowering their overall gas supply costs. While average delivered prices for C&I users have begun to reflect current market pricing dynamics—as older and lower priced GSAs have expired and been replaced with new higher priced GSAs, and the average duration of GSAs has decreased—the retailers' average cost of supplying these users not increased as quickly. As a result, the retailers' average portfolio margins have increased, most significantly in 2017 and 2018.

The confluence of factors that disrupted the gas market around 2016 and 2017—at a time when the gas market was already undergoing a significant transition—impacted the major retailers' outlook for the gas market and affected their approach to supplying C&I users. Box 4.3 below describes the retailers' response to market conditions during this period.

Box 4.3: Retailer C&I market strategies

While some very large C&I gas users have in the past purchased wholesale gas from producers and arranged their own transportation, most users have relied on the major retailers to secure gas supply on a delivered basis to their locations. Prices paid to retailers have reflected historically low commodity gas costs and have been relatively stable over time.

Information obtained by the ACCC from the major retailers shows that most considered that there was an increased level of wholesale market risk in the period between 2015 and 2017, mainly driven by tight supply and demand conditions in the east coast market. In this environment, the retailers generally viewed supplying C&I users as carrying greater risk than previously.

One of the retailers made a decision that, for gas supplied in 2018 and beyond, it would only purchase gas to supply a C&I customer if that customer was contractually committed to purchase the gas. Another retailer, for a period during 2017, implemented a strategy where it did not make offers to new customers to ensure that it was able to meet the needs of existing customers.

Further, a retailer which generally holds a 'short' supply position for gas sales over the short- to medium-term told the ACCC that this position became more pronounced in 2017 due to C&I customers' reluctance to enter into long term contracts at the prices being offered at this time. This also meant that contracts with C&I users were being executed much closer to the supply period, increasing the price risk that would be carried by this retailer.

The market conditions facing the retailers at this time, coupled with the increased perceived risk in supplying C&I users and the reluctance of C&I users to enter into longer term GSAs, led to a reduction both in the number of offers made and the number of retailers making them, as well as the number of GSAs being executed. In early 2017, the prices of commodity gas offers increased significantly, up to more than $20/GJ, and remained above $10/GJ for most of the year.[162]

The two retailers that were most active in making offers during this period have told the ACCC that they based the prices of their offers on their own expectations of market prices for wholesale gas during the relevant period of supply. For one of these retailers, the short position of its portfolio meant that the prices it was offering reflected its view of the value of gas that had yet to be procured in order to supply the customer. Information provided to the ACCC by this retailer shows that its expectations of wholesale gas prices across the market for the 2018 supply year almost doubled over a 12-month period – from between $7 and $8/GJ in early 2016 (depending on the state) to $14/GJ in March 2017 before falling to around $9/GJ by the end of 2017.

The other retailer that was active in making offers over this period, however, has confirmed that it only offers uncontracted gas to customers (that is, gas that it has previously procured but not sold).

As found by Oakley Greenwood in its 2018 report, gas commodity prices agreed in new GSAs by C&I users began gradually increasing from historical levels around 2009–10, and had increased to around $8–9/GJ by 2015–16.[163] The ACCC has previously reported that the average level of commodity gas price offers made by retailers to C&I users with annual contract quantities of 0.5 PJ or more has fluctuated between $9 and $12/GJ since late 2017.[164] While most of the high-priced offers made by retailers in 2017 were rejected by these C&I users, some were accepted.[165] As the prices of retailer offers fell over 2017, and as C&I users' previous gas supply agreements were nearing expiration, more GSAs between retailers and C&I users were executed.[166]

Most of the GSAs the ACCC has seen between retailers and C&I users of 0.5 PJ per annum or more that were executed during and since 2017 have been priced within this $9–12/GJ range.[167] It appears that these GSAs entered into by C&I users in this period, as well as

162 ACCC, *Gas Inquiry 2017–2020 Interim report*, April 2018, p. 41.
163 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 84.
164 ACCC, *Gas Inquiry 2017–2020 Interim report*, April 2019, p. 31.
165 ACCC, *Gas Inquiry 2017–2020 Interim report*, December 2018, p. 74.
166 ACCC, *Gas Inquiry 2017–2020 Interim report*, April 2018, p. 10.
167 ACCC, *Gas Inquiry 2017–2020 Interim report*, December 2018, p. 94.

those executed at around $8–9/GJ in 2015–16 and to a lesser extent those in the years prior, have driven the increase in delivered prices shown in the charts above.

The extent to which this increase in margins to C&I customers is only transitory is not yet clear, and it may represent only a passing advantage to retailers until their lower priced legacy GSAs expire and GSAs that reflect current market conditions and prices are executed. Further, the lower level of supply to C&I users by retailers may have been taken up by new retailers and gas producers in large part (discussed further below), which may facilitate increased competition in supplying this market segment with potential impacts on retailer margins for supplying these users. The ACCC will undertake further analysis to determine to what extent margins are a function of the uncertain supply-demand dynamics or indicative of more long term structural and competition concerns.

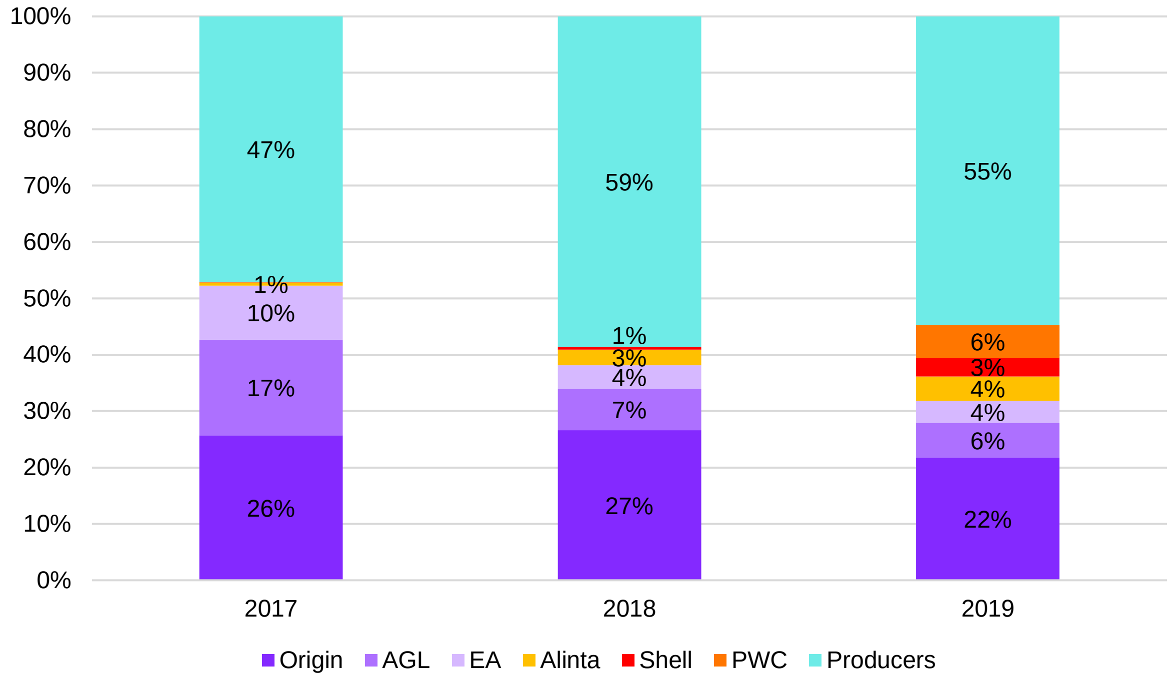
The market appears to be changing for some C&I users

The retailers' change in approach to supplying C&I users over 2016 and 2017 appears to be largely a response to changes in market conditions, the tightness of supply in the market, and the perceived increased risks associated with supplying these customers in that environment. It appears to have resulted in a reduction in the retailers' offers of gas to C&I users at the time. As found in the ACCC's first inquiry report in September 2017, some key suppliers, including retailers, were not actively marketing gas to C&I users over this period.[168] The ACCC observed in that report that, according to one supplier, there was 'evidence of retailers, with the exception of Origin, declining to provide proposals for continued supply of gas throughout 2017 and beyond, citing lack of portfolio supply.'[169]

While AGL and EnergyAustralia have more recently increased the number of offers for gas supply to a range of C&I users with annual contract quantities of 0.5 PJ or more across the east coast, information collected by the ACCC shows that the quantities they have supplied to C&I users overall have fallen significantly over the past several years. This is demonstrated in chart 4.7 below, which shows retailer and producer shares of gas supplied to C&I users in 2017 and 2018, as well as gas contracted for 2019.

168 ACCC, *Gas Inquiry 2017–2020 Interim report*, September 2017, p. 11.
169 ACCC, *Gas Inquiry 2017–2020 Interim report*, September 2017, p. 11.

Chart 4.7: C&I market shares of retailers and producers



Source: ACCC analysis of information provided by suppliers.

Note: Market shares are relative to the retailers shown in the chart and the producers from which the ACCC has collected information for this report. The chart excludes supply to C&I users by other suppliers. Data for 2019 is based on the quantity of gas contracted with C&I users as at April 2019.

Chart 4.7 shows that AGL and EnergyAustralia's combined C&I market share has fallen from 17 per cent in 2017 to 10 per cent for gas contracted in 2019. Other information collected by the ACCC shows that AGL and EnergyAustralia's supply to C&I users also fell substantially between 2014 and 2016. In contrast, Origin has increased the quantities it has supplied to C&I users since 2017 (albeit by a much lower amount than the decrease in supply from other retailers) but due to the increase in supply to C&I users by other retailers and producers, its overall market share has fallen.

However, while supply by the major retailers to C&I users has declined overall in recent years, activity in the C&I market among smaller and new entrant retailers appears to have increased. Information collected by the ACCC on offers from suppliers across the east coast for annual contract quantities over 0.5 PJ shows that, since around the middle of 2017, Alinta Energy and Shell Energy Australia have consistently made offers to these C&I users, and have also contracted significant volumes, appearing to make up some of the reduced volume supplied by the major retailers. Further, more recently, Power and Water Corporation (PWC) in the Northern Territory has also been active in making offers to and contracting with C&I gas users in the east coast market for gas supply in 2019 and beyond.

Chart 4.7 shows that the share of volumes supplied by the major retailers to C&I users fell from 52 per cent in 2017 to 32 per cent in 2019. In contrast, the share of volumes supplied and contracted by Alinta, Shell and PWC increased significantly, collectively increasing from 1 per cent in 2017 to 13 per cent in 2019.

From interviews conducted with Alinta and Shell for this report, the ACCC understands that these suppliers have, over the past several years, actively sought to enter the C&I market on the east coast. As noted above, these retailers have been increasingly active since 2017 in offering gas supply to C&I users with annual contract quantities over 0.5 PJ across the east coast. Chart 4.7 above shows these suppliers have been successful in contracting with C&I

users more broadly and have significantly increased the quantities supplied, with almost a third of C&I volumes contracted by retailers for 2019. Further, the ACCC understands that both suppliers are currently actively engaged in the market and are open to expanding their supply.

Alinta and Shell have told the ACCC that they have been effectively able to manage their expanding role in the East Coast Gas Market, and in particular supplying C&I users. Both suppliers have told the ACCC that they have successfully been able to contract for additional pipeline and storage capacity throughout the east coast as it has been required.

In addition to showing the decline in volumes supplied to C&I customers by major retailers and the increase in supply by smaller retailers, chart 4.7 above shows that overall supply by these retailers to C&I users has fallen between 2017 and 2019. Other information collected by the ACCC shows that in 2014, the major retailers collectively supplied 158 PJ to C&I users. By 2018, the total volume supplied by retailers (including Alinta and Shell) to C&I users had fallen to 101 PJ, with 111 PJ contracted for 2019 (with the inclusion of PWC).

While there has been an increase in supply to C&I users by Origin, Alinta, Shell and PWC, this does not appear to have matched the decline in supply by AGL and EnergyAustralia. Instead, it appears that that there has been a significant increase in supply by producers to C&I users that appears broadly commensurate with the drop in supply by retailers (and, as noted in section 3.5, some users have elected to secure gas supply from short-term trading markets). Information collected by the ACCC shows that supply by producers to C&I users went from around 114 PJ in 2017 to 143 PJ in 2018, with 134 PJ contracted for 2019. In addition, data collected from pipeline operators shows that there has been an increase in activity among C&I users in contracting for capacity on some major pipelines.

This indicates that some C&I users have elected to contract directly with producers and make their own transportation arrangements rather than have their gas supplied by a retailer. As discussed in chapter 3, we have spoken to some C&I users who have confirmed that they have made this change. Notably, in September 2018 Santos announced that it had entered into a long-term GSA with Brickworks, a large C&I user which had previously been supplied by a major retailer.[170]

More low cost supply needed

As noted above, the ACCC has not conducted a comprehensive competition analysis of the retail gas market at this stage. The analysis presented in this chapter focuses on the average prices and estimated margins of the major retailers for mass market and C&I customers, and how these have been affected by recent changes in the pricing and supply-demand dynamics within the East Coast Gas Market.

The ACCC considers that further monitoring and analysis is required to fully understand the drivers of the significant margins being generated by the major retailers from mass market and C&I customers. The level of margins is concerning and the ACCC will further investigate whether they are due to existing low-cost legacy gas contracts, or structural and competition issues in the market.

Regardless, a key way to improve pricing outcomes for all C&I users—particularly the majority which are located in the southern states—is with the production of additional, lower cost supply in the southern states by a diversity of suppliers.

As discussed in chapter 1, the supply-demand balance in the southern states remains tight, and AEMO forecasts indicate that current estimates of production from proved and probable

170 Santos, 'Santos signs new long term domestic gas supply deal with Brickworks', 12 September 2018, https://www.santos.com/media-centre/announcements/santos-signs-new-long-term-domestic-gas-supply-deal-with-brickworks/.

reserves are not likely to be sufficient to meet expected market demand over the next decade. If additional supply does not come on in the southern states in time to meet expected demand, then gas would likely need to be transported from Queensland or imported through any future LNG import terminal—two scenarios that would not be likely to provide any price relief to C&I users.

Prices offered and executed in recent GSAs for annual contract quantities of 0.5 PJ or more by all retailers in the southern states continue to mostly be at or above LNG netback levels. They could be even higher for those C&I users consuming less gas. The charts above show that average prices paid to retailers by these C&I users have trended towards these levels despite increased activity by new entrants in the C&I market in recent years. At the same time, the major retailers' portfolio cost of gas is expected to increase as low-priced legacy contracts expire and the retailers recontract at higher prices under current wholesale market conditions. While a continuation of these trends would ultimately see the margins of the major retailers decline, on its own it would not be likely to lead to lower prices for C&I users.

As discussed above, some large C&I users have over recent years decided to engage directly with producers and pipeline operators to secure gas supply and transportation, and have achieved better outcomes as a result. However, this may not be an option for smaller C&I users, which are generally not able to source gas and pipeline capacity directly from producers and pipeline operators. While some smaller users have formed a buyers group to purchase wholesale gas, with retailers acting as intermediaries for transportation, this will not be a solution for many others.

While there have been developments over recent years that have led to a reduction of the dominance of the major retailers in the market to supply some C&I users, the ACCC considers that retailers will remain an important source of supply for smaller and medium size C&I users. Further understanding retailers' supply of gas to these users, particularly those who can only be supplied by one retailer, will be a priority for the ACCC.

5. Transportation pricing

5.1. Key points

- Between 31 August 2018 and 15 March 2019, 15 new gas transportation agreements (GTAs) and 75 variations were executed, of which 29 resulted in new prices. Most recent variations have involved changes to allow shippers to use the recent capacity trading reforms.
- Recent market-based and regulatory changes are influencing pipeline operators' contracting activities, pricing strategies and the prices payable for transportation and pipeline storage services. Overall there are encouraging signs that recent reforms are leading to positive market changes.
- Changing market conditions have resulted in:
    - A significant increase in the number of shippers seeking shorter term contracts for firm forward haul transportation services and an increase in the demand for as available and interruptible transportation and pipeline storage services.
    - A greater number of C&I gas users seeking to contract directly with pipeline operators. In a number of these cases, larger C&I gas users have been able to negotiate substantial discounts from the pipeline operators' standing prices.
    - A greater number of smaller retailers contracting with pipeline operators, some of whom are also supplying regional areas.
- Some pipeline operators appear to be becoming more customer-focused, developing new services to meet the changing needs of shippers (some of which appear designed to overcome the impediments that may otherwise be posed by most favoured nation clauses).
- The incidence of excessive pricing of as available and interruptible transportation services has decreased since the ACCC's 2015 Inquiry. The recently implemented capacity trading reforms are expected to place further downward pressure on these prices (and, to a lesser extent, pipeline storage), through competition from shippers and the day-ahead auction of contracted but un-nominated capacity.
- While there have been improvements, some concerns remain. Specifically:
    - Prices on some pipelines have fallen significantly, while in other cases there has been a material increase in prices. The ACCC is concerned about these increases, given our prior findings of monopoly pricing. It therefore intends to consider the cost reflectivity of prices charged by pipeline operators in the latter half of this year.
    - While some large C&I gas users have been able to negotiate substantial discounts to their transportation charges, the ACCC is concerned that smaller C&I gas users may not be faring as well. A number of C&I gas users with older GTAs also appear to be paying prices that are towards the upper end of the range on some pipelines. The ACCC will therefore continue to monitor the prices offered to C&I gas users.
- Some new retailer entry is occurring in regional areas, however concerns continue to be raised with the ACCC about the inability of prospective users to access pipelines in regional areas where the pipeline's capacity has been fully contracted to an existing retailer. The ACCC will examine these concerns in the latter half of this year.
- The ACCC will also review the effect of the capacity trading reforms on the demand for transportation services and the behaviour of pipeline operators and shippers. In addition, we will continue to monitor pipeline operators' pricing and contracting activities.

5.2. Introduction

The ACCC's 2015 Inquiry found that while pipeline operators had been responding well to the changes underway in the East Coast Gas Market by offering more flexible services and by carrying out major investments, there was evidence that a large number of pipeline operators were engaging in monopoly pricing.[171]

In the intervening period, the supply-demand balance in the East Coast Gas Market has tightened (although as noted in section 1.4, conditions are starting to ease more recently), which is having a range of effects on gas transmission pipelines. It has, for example, resulted in gas flows across the East Coast Gas Market becoming more dynamic, with the direction of some gas pipelines changing throughout the year in response to changes in the supply-demand balance in particular locations. It has also resulted in an increasing number of shippers seeking more flexible pipeline services to manage the volatility in their demand for gas and to exploit arbitrage opportunities.

The tighter conditions have also prompted the development of a number of new pipelines, including the Northern Gas Pipeline (NGP) (commissioned in January 2019), the Reedy Creek to Wallumbilla Pipeline (commissioned in June 2018), and the pipeline that Jemena is in the process of developing to bring Senex's Atlas field in the Surat basin to market.[172]

A range of reforms to the regulatory framework applying to gas pipelines have also occurred over this period, many of which were prompted by the findings of the ACCC's 2015 Inquiry. For example:

- In August 2017, the Council of Australian Governments Energy Council (Energy Council) implemented a new information disclosure and arbitration framework for non-scheme pipelines (for ease of reference this framework is referred to as 'Part 23' in this chapter). This framework was implemented in response to the *Examination of the current test for the regulation of gas pipelines* that was conducted by Dr Michael Vertigan (AC),[173] which recommended that steps be taken to reduce the information asymmetry and imbalance in bargaining power shippers can face when negotiating with pipeline operators on non-scheme pipelines.[174] Part 23 is discussed further in chapter 6.
- In July 2018, the Australian Energy Market Commission (AEMC) completed its review into the scope of economic regulation applied to scheme ('covered') pipelines.[175] Amongst other things, the AEMC found that some aspects of the regulatory framework applying to full and light regulation pipelines were not effectively constraining the market power of pipeline operators, or supporting informed negotiations with shippers. The AEMC therefore recommended a range of changes to the regulatory framework applying to full and light regulation pipelines, many of which were implemented in March 2019.[176]
- In November 2018, the Energy Council implemented the capacity trading reform package, the objective of which is to improve the efficiency with which capacity is allocated and used on transportation facilities by fostering the development of a more liquid secondary capacity market. Amongst other things, these reforms provided for AEMO to develop a capacity trading platform shippers can use to trade spare capacity and a day-ahead auction of contracted but un-nominated capacity (herein referred to as the 'day-ahead auction'), both of which commenced on 1 March 2019.

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

172 Jemena, *Media release: Jemena and Senex partner to fast-track new gas supply to market*, 18 June 2018.

173 Vertigan, M, *Examination of the current test for the regulation of gas pipelines*, 14 December 2016.

174 A non-scheme pipeline is a pipeline that has not been classified as a 'scheme' pipeline.

175 AEMC, *Final Report: Review into the Scope of Economic Regulation Applied to Covered Pipelines,* 3 July 2018.

176 AEMC, Rule Determination: Regulation of Covered Pipelines, 14 March 2019.

The pipelines to which these reforms apply are set out in figure 5.1, while box 5.1 provides more detail on the forms of regulation that may be applied to gas pipelines (i.e. full regulation, light regulation and Part 23).

Box 5.1: Forms of regulation

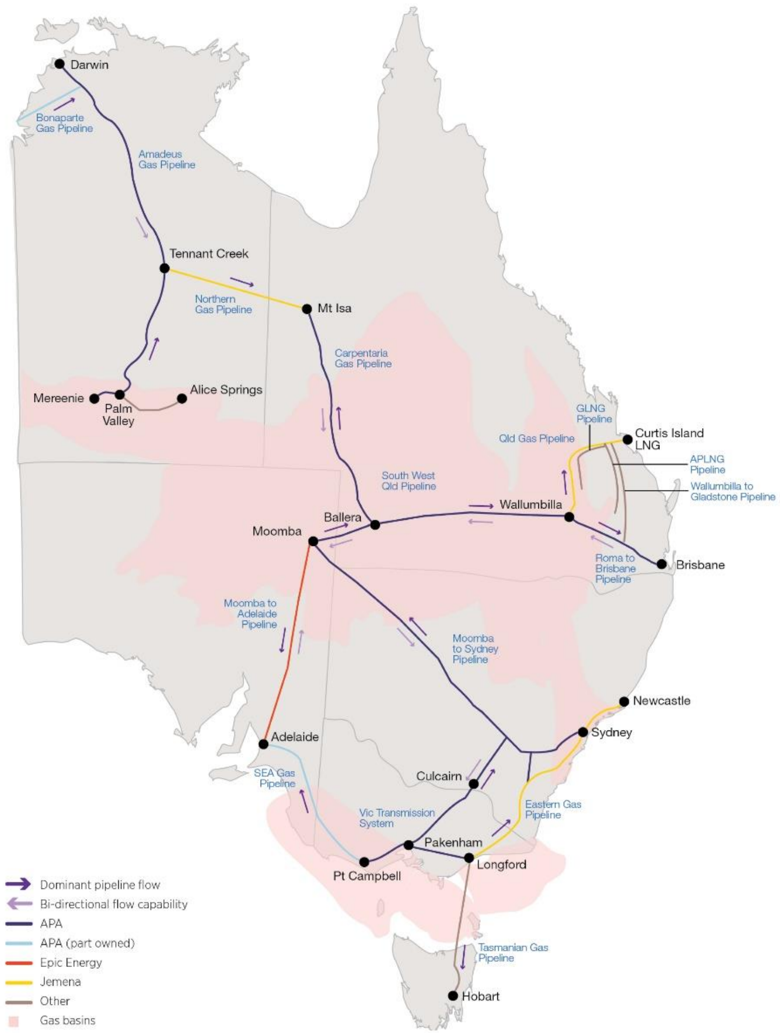
Following the introduction of Part 23, there are now three forms of regulation that may be applied to gas transmission pipelines:

- **Full regulation**: This form of regulation, which can only be applied to a scheme (covered)[177] pipeline, requires the pipeline operator to periodically submit an 'access arrangement' to the Australian Energy Regulator (AER) for approval of the price and other terms and conditions of access to the reference service(s) set out in the proposed access arrangement. While AER approval is required, the pipeline operator and shippers on contract carriage pipelines are free to enter into an agreement that differs from the access arrangement. However, if an access dispute arises, the arbitrator (the AER) is required to give effect to the access arrangement.
- **Light regulation**: This form of regulation, which again can only be applied to a scheme pipeline, places greater emphasis on information disclosure and negotiation, with the AER only playing a role if the dispute resolution provisions are triggered. A light regulation pipeline is also prohibited from engaging in inefficient price discrimination and a range of other conduct that may adversely affect access and/or competition in other markets.
- **Information disclosure and arbitration framework (Part 23)**: This form of regulation, which applies to 'non-scheme pipelines' providing third party access, requires pipeline operators to disclose a range of information to facilitate timely and effective commercial negotiations. It also sets out the process for requesting access, negotiations and the conduct of an arbitration (which must be completed within 50-90 business days). In contrast to full and light regulation, if the arbitration mechanism is triggered then the arbitration will be conducted by a commercial arbitrator selected from a pool of arbitrators established by the AER.

Given the changes that have occurred over the last three years, it is relevant to consider what, if any, effect they have had on the behaviour of pipeline operators. The ACCC has therefore used its compulsory information gathering powers to conduct a more detailed review of the GTAs that have recently been entered into or varied, pipeline operators' pricing strategies and the prices paid by shippers for transportation and pipeline storage services. The results of this review are set out in the remainder of this chapter.

177 The term 'covered pipeline' means a pipeline that is subject to a coverage determination or has been deemed to be a covered pipeline. A pipeline operator that is proposing (or has commenced but not yet commissioned) a greenfields pipeline, may apply for a 15 year no-coverage determination, which exempts it from being a covered pipeline. This determination does not, however, exempt the pipeline from Part 23.

Figure 5.1: Regulatory status of transmission pipelines



Current regulatory status of major transmission pipelines

State	Pipeline	Owner	Regulatory Status	Capacity Trading Reforms
NSW	Moomba Sydney Pipeline **(MSP)**	APA	Non-scheme pipeline: Moomba to Marsden Light regulation: Remainder	✓
	Eastern Gas Pipeline **(EGP)**	Jemena	Non-scheme pipeline	✓
SA	Moomba to Adelaide Pipeline System **(MAPS)**	Epic Energy	Non-scheme pipeline	✓
	South East South Australia Pipeline **(SESA)**	APA	Non-scheme pipeline	✓
	South East Pipeline System **(SEPS)**	Epic Energy	Non-scheme pipeline*	✓
	Port Campbell to Adelaide Pipeline **(PCA)**	SEA Gas	Non-scheme pipeline	✓
	Port Campbell to Iona Pipeline **(PCI)**	SEA Gas	Non-scheme pipeline	✓
Vic	Victorian Transmission System **(VTS)**	APA	Full regulation	×
Qld	Roma to Brisbane Pipeline **(RBP)**	APA	Full regulation	✓
	South West Queensland Pipeline **(SWQP)**	APA	Non-scheme pipeline	✓
	Queensland Gas Pipeline **(QGP)**	Jemena	Non-scheme pipeline	✓
	Carpentaria Gas Pipeline **(CGP)**	APA	Light regulation	✓
	Berwyndale to Wallumbilla Pipeline **(BWP)**	APA	Non-scheme pipeline	✓
	Darling Downs Pipeline **(DDP)**	Jemena	Non-scheme pipeline	✓
	Wallumbilla to Gladstone Pipeline **(WGP)**	APA	Non-scheme pipeline 15-year no coverage	✓
	APLNG Pipeline	APLNG	Exempt non-scheme pipeline* 15-year no coverage	×
	GLNG Pipeline	GLNG	Exempt non-scheme pipeline* 15-year no coverage	×
Tas	Tasmanian Gas Pipeline **(TGP)**	Palisade Asset Management	Non-scheme pipeline	✓
NT	Amadeus Gas Pipeline **(AGP)**	APA	Full regulation	✓ but subject to derogation from day-ahead auction
	Northern Gas Pipeline **(NGP)**	Jemena	Non-scheme pipeline but subject to 15yr derogation from Part 23	✓ but subject to derogation from day-ahead auction

*Exemptions obtained because these pipelines are not providing third party access.

5.3. The nature of contracting is changing on transmission pipelines

In the December 2018 interim report, the ACCC reported on the number of new GTAs and variations that had been entered into on the following pipelines in the East Coast Gas Market between 1 August 2017 (the commencement date for Part 23) and 30 August 2018:

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

In the intervening period (31 August 2018 – 15 March 2019), 15 new GTAs were entered into and 75 variations to existing GTAs were executed (of which 29 resulted in new prices being determined for existing services or in relation to new services).

The analysis has now been updated to include all new GTAs and variations entered into between 1 August 2017 and 15 March 2019. This analysis revealed that a total of 37 new GTAs were entered into over this period and 156 variations to existing GTAs were executed. Of those 156 variations, 53 resulted in new prices being determined for existing services or for new services. The remaining variations involved changes to other aspects of GTAs, such as receipt and delivery points, contract volumes and contract duration. While these variations did not involve changes in price, many of them provide the shipper with greater flexibility to manage their portfolio in a more efficient manner and to respond more effectively to the volatility present in the East Coast Gas Market.

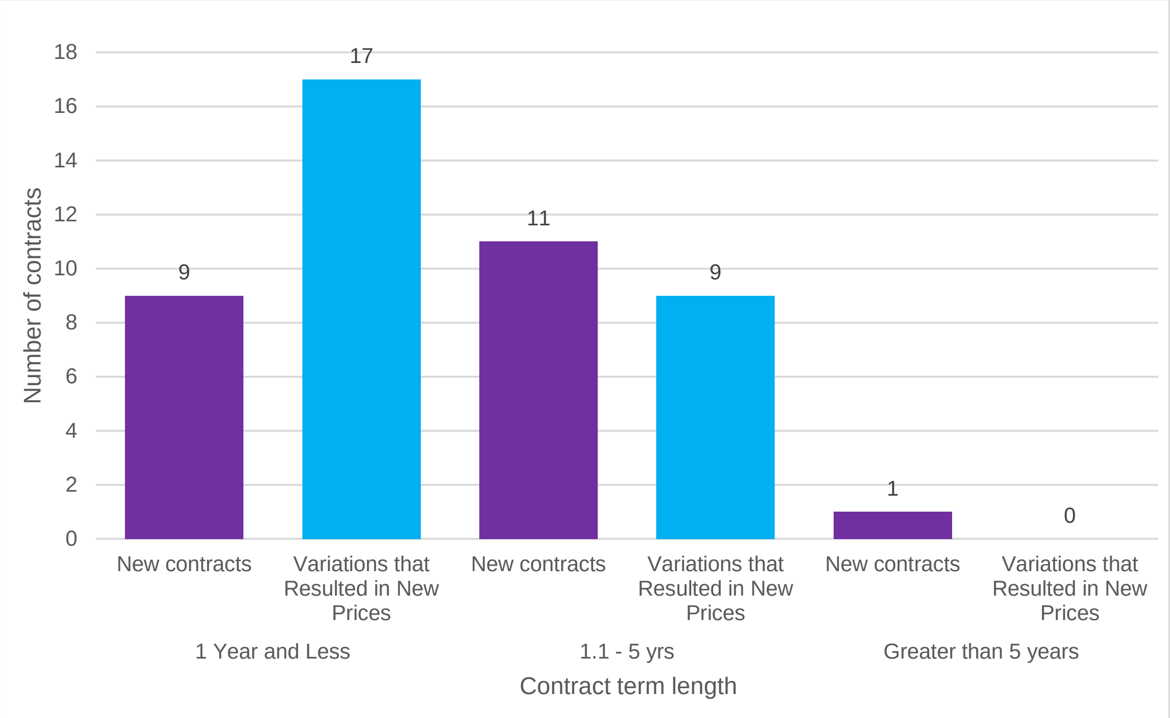
Of the 90 new GTAs and variations resulting in new prices, 47 related to the provision of firm forward haul services. The remainder related to the provision of other transportation, pipeline storage and ancillary services, such as 'as available' or interruptible transportation services, park and loan services, backhaul services,[178] redirection services and capacity trading-related services. Most of the more recent variations involved changes to existing GTAs to enable shippers to use the capacity trading reforms, which were implemented in late 2018. Further detail on some of the trends we have observed from the more recent contracts are outlined below.

5.3.1. Shippers are adopting a shorter term approach to contracting

Chart 5.1 shows the number of GTAs and price variations for firm forward haul services by contract term length. Before examining this chart, it is worth noting that there are a number of older long-term contracts that are not captured in this chart because they were entered into prior to August 2017. The chart does not therefore represent all GTAs that are currently in force.

[178] A back haul service involves the notional 'transportation' of gas in the opposite direction to the predominant flow of gas. The transportation is notional because the service does not actually result in the physical transportation of gas in the opposite direction. Rather the service involves a physical swap with gas 'exchanged' at the point at which it is intended to enter the pipeline for an equivalent amount of gas at the backhaul delivery point. The practical effect of the back haul service is that the net forward haul flow is offset by the volumes of gas nominated for back haul. If there is an insufficient volume of gas being transported on a forward haul basis then the back haul service will be interrupted, which is why this service is usually only sold on an interruptible basis.

Chart 5.1: New Gas Transportation Agreements and Price Variations for firm forward haul services by term length



As shown in chart 5.1, the majority (26) of the 47 new GTAs and variations resulting in new prices relating to firm forward haul services were for contract terms of one year or less.

While there have been some longer term GTAs entered into in the last six months, we continue to observe a trend toward shorter term contracts on existing pipelines, with only one contract entered into since 1 August 2017 with a term of five years or longer. This trend is also apparent in the material pipeline operators have provided on the negotiations that took place between 21 May 2018 and 15 March 2019.

The trend toward shorter term contracts is consistent with what the ACCC has previously observed in relation to GSAs. It is also consistent with feedback users have provided on the effect that uncertainties in the market regarding gas supply-demand dynamics and gas prices are having on their willingness to contract for longer periods. There are some signs of gas users considering entry into longer term GSAs to underwrite the development of new gas fields. It may, however, take some time for this to transpire into longer term GTAs.

5.3.2. Shippers are seeking more flexible services

Consistent with the observations regarding shorter term contracting, a larger number of shippers are now also relying on the flexibility offered by as available[179] and interruptible transportation services to manage the volatility in their demand and to exploit arbitrage opportunities across gas and electricity markets. The increased demand for these services has prompted at least one pipeline operator (APA) to introduce a range of shorter term services, including a short-term firm service, a day-ahead firm service, a within-day service and an interruptible service.

Whether or not shippers continue to seek these types of services from pipeline operators, or decide to rely instead on the day-ahead auction and/or the capacity trading platform remains to be seen. However, early indications are that the auction is starting to have an effect on the way in which shippers procure these types of services, with a number of shippers now using

[179] For the purposes of this chapter, the term 'as available' is also used to refer to the short-term firm services offered by APA, which have a term less than 12 months.

the auction to procure reasonable quantities of capacity on a day-ahead basis (see section 1.8). The ACCC intends to conduct a closer review of the effect of these reforms on the demand for services and the behaviour of both pipeline operators and shippers with firm capacity.

In a similar manner to as available and interruptible services, an increasing number of shippers are using pipeline storage services (referred to as park[180] and/or park and loan[181] services). This trend is consistent with our prior observations about producers offering buyers less flexibility in their GSAs to manage daily or seasonal variations in demand.[182] It is not surprising therefore that buyers are looking for alternative ways to manage those risks. The increased uptake of these services may also reflect the greater level of volatility in the gas and electricity markets, with participants using storage services to manage the volatility and to exploit any arbitrage opportunities.

In addition to these trends, we have observed a material increase in the number of shippers entering into contracts to transport gas from Queensland to the Southern States. In some cases, this has involved the use of as available or interruptible transportation services on the South West Queensland Pipeline (SWQP), while in other cases it has involved the use of a bundled transportation service on the SWQP and Moomba to Sydney Pipeline (MSP), between Wallumbilla and either Sydney or Culcairn.

5.3.3. Greater numbers of C&I users and smaller retailers are contracting with pipeline operators, but access to regional pipelines may still be an issue

Our analysis of recent contracts shows that a greater number of large C&I gas users are contracting directly with pipeline operators, rather than procuring their gas and transport from retailers on a bundled basis. This trend is also apparent in the material pipeline operators provided on the negotiations that took place between 21 May 2018 and 15 March 2019.

The analysis shows that some smaller retailers are also contracting directly with pipeline operators, a number of whom are also supplying regional areas. Concerns nevertheless continue to be raised with the ACCC about the inability of prospective users to access pipelines in regional areas in instances where the pipeline's capacity has been fully contracted to an existing retailer.

Concerns have, for example, been raised about access to the Carisbrook to Horsham pipeline in Victoria, which is owned by Gas Pipelines Victoria.[183] The ACCC understands that this pipeline is currently fully contracted to EnergyAustralia, which means that unless another prospective user is prepared to underwrite a pipeline expansion, they cannot independently transport gas along this pipeline unless EnergyAustralia on-sells some of its capacity.[184]

Similar concerns have also been raised about access to regional pipelines in other states, as highlighted by some of the feedback we received through our user survey (see box 5.2). Given concerns continue to be raised about the accessibility of capacity on regional pipelines, the ACCC intends to look at this issue in more detail in the latter half of 2019.

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180 Park services allow users to inject more gas into a pipeline than they take out on a particular day, up to a specified level and to store that gas in the pipeline. The additional gas supplied into the pipeline may be withdrawn by users at a later point in time, subject to constraints in their transportation contracts.

181 In addition to allowing users to store gas on the pipeline, park and loan services allow users to inject less gas than it takes on any given day (a loan), up to a specified level.

182 See for example, ACCC, *Gas inquiry interim report*, September 2017, p. 51.

183 Gartlan, J, *Origin and Red Energy may enter the Grampians Wimmera gas market*, 26 February 2019, https://www.araratadvertiser.com.au/story/5839561/new-competition-may-break-gas-monopoly-in-the-grampians-wimmera/.

184 The Carisbrook to Horsham pipeline has a conditional exemption from some of the elements of the capacity trading reforms, including the day-ahead auction.

Box 5.2: Concerns raised through user survey

One C&I gas user that employs about 100 workers at a single east coast site, noted that their delivered gas and transportation costs exceed $25/GJ with transportation costs constituting two thirds of the cost (around $15/GJ). In the user's latest negotiations with its supplier, it was quoted a price exceeding $30/GJ. This user described the situation this way.

> *"It's unfathomable that we are so close to a major gas hub and the price continues to remain extremely high, more than $25/GJ for total delivered cost. Our business is intensely trade exposed and faces the prospect of closure and significant job losses if it cannot match imported pricing for our products".*

This user must transport gas along a regional pipeline with only one retailer able to supply gas to them. The user has approached a number of other suppliers.

> *"It has been conveyed to us by retailers we approached for gas pricing that all the gas line capacity has been purchased thus other retailers are unable to trade gas on the line. It is not clear to us if the physical capacity of the line is consumed or fully utilised".*

Another large C&I gas user in the east coast informed us that they had previously been supplied by a retailer that held all the capacity on a regional lateral, but decided to seek offers from a number of other gas suppliers.

While the user found better deals for gas, access to transportation capacity was an issue. The user noted that while they had approached their original retailer about relinquishing capacity, they were told the retailer had other uses for the capacity but a bundled gas and transport offer was available.

As this price was still higher than other suppliers with no capacity the user indicated that it intended to discuss the issue with the ACCC. The retailer has now amended its position and agreed to a commercially satisfactory arrangement with the user.

5.4. A number of factors are influencing pricing strategies

To better understand the current contracting environment, the ACCC obtained board documents from pipeline operators that discussed pricing strategies. These board documents provide some insight into the factors that are influencing the prices offered and charged by pipeline operators.

Revenue is unsurprisingly a key consideration for businesses when determining prices. However, the extent to which revenue is taken into account when determining prices varies across pipeline operators. The ACCC has seen evidence of one pipeline operator, in an internal document dated prior to the commencement of Part 23, setting a minimum acceptable level of revenue as "a benchmark to inform the walkaway point for negotiations with individual shippers". The internal document appears to show the pipeline operator "back-solving" prices for some prospective GTAs to achieve this minimum level of revenue. Notwithstanding this, they explained that such tariffs were expected to vary depending on the non-price terms ultimately negotiated, particularly the duration of the agreement. The pipeline operator indicated a willingness to offer lower prices where contracts were for a longer-term of at least five years, and would seek to negotiate a materially higher tariff for a one- to two- year deal.

As noted above, shorter-term contracts are becoming more prevalent. One pipeline operator attributed this to "the increasing volatility and high gas pricing", which means customers will only contract for pipeline capacity "to the extent that, and only so long as, they have secured a gas supply agreement with a producer/supplier". This pipeline operator also noted that the trend toward shorter-term contracts was making it more difficult for pipeline operators to "underpin pipeline investment and secure a long-term transportation position" which, in turn, appears to be influencing prices.

Most favoured nation (MFN)[185] and revenue rebate clauses,[186] agreed to under legacy or foundation contracts, also appear to be affecting the prices that some pipeline operators are willing to offer. One pipeline operator commented in its board documents that "MFNs are an active consideration in [its] contracting". While these types of clauses have not been observed in recently executed GTAs, the handful that exist are expected to remain in operation until at least 2034 (when the longest of these contracts expire).[187] Pipeline operators wanting to avoid triggering these clauses – in particular, MFN clauses – would need to charge other users prices that are no less than those payable under the existing agreements. Otherwise, the impact of these clauses would result in a loss of revenue. It is worth noting though that MFN clauses for firm services do not prevent pipeline operators from offering other services at a lower price than the firm price contained in the contract with the MFN clause.[188]

Another factor that some pipeline operators noted affects their pricing is competition or the threat of competition. Internal documents, for example, show some tariffs being set to "maintain a competitive position", and also taking into account "competing energy sources" as a factor that influences customer contracting. The entry of the NGP was cited as the reason for the fall in the CGP standing price, in response to potential new competing supply to Mount Isa. The regard to competition is reinforced by some of the pricing methodologies published by pipeline operators.[189] For example, APA notes in its methodology used to determine standing prices that it has "sought to use prices in contracts negotiated in competitive circumstances (such as pipeline development, alternative fuel competition or other competitive circumstances)".[190] The Board documents also show that some pipeline operators are pricing at levels that are designed to enable shippers to compete in their downstream markets.

The ACCC has further observed that some pipeline operators are becoming more customer-focused, emphasising customer relations and making active efforts to support larger C&I gas users.[191] For example, some pipeline operators have sought to support the commercial viability of larger C&I gas users by offering discounted and bundled deals. An example of this is last year's announcement by APA and Jemena that each had entered into GTAs (which APA has since extended)[192] to deliver gas to Incitec Pivot at its Gibson Island Facility.[193] The arrangement involves a total of five pipelines, four of which are owned and operated by APA. APA has described the nature of this deal in its board papers as the "most complex delivery solution by APA or any other gas transporter in Australia". APA and Jemena's willingness to negotiate and enter into such a deal to support the continued operation of Incitec is a positive development.

185 These clauses give the capacity holder a right to pay the same price as that payable by another shipper for an equivalent cheaper service.

186 These clauses give a capacity holder the right to be paid some or all of the revenue that a pipeline operator derives from supplying a specified pipeline service to another party.

187 This relates to contracts that include a most-favoured nation clause.

188 ACCC, *Inquiry into the east coast gas market*, April 2016 p. 148.

189 The ACCC notes that it is also reflected in the objective of Part 23, which is "to facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which, for the purposes of [that] Part, is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market": NGR s 546(1).

190 APA, *APA Pricing Methodology*, 31 January 2018, p 2.

191 The ACCC notes some pipeline operators have signed up to the Energy Charter, which came into effect on 1 January 2019.

192 APA, *APA extends GTA with Incitec Pivot keeping Gibson Island plant operating*, 4 June 2019, https://www.apa.com.au/globalassets/asx-releases/2019/2019-06-04-apa-extends-gta-with-incitec-pivot.pdf.

193 APA, *Jemena announces new gas transportation contract*, 25 June 2018; https://www.apa.com.au/news/asx-releases/2018/apa-signs-landmark-deal-with-incitec-pivot/; Jemena, *Jemena announces new gas transportation contract*, http://jemena.com.au/about/newsroom/media-release/2018/jemena-and-senex-partner-to-fast-track-new-gas-(1).

The ACCC has also seen an example of a pipeline operator lowering the prices payable by a large C&I gas user through its GTA with a retailer.[194] In this case, the ACCC has observed that the retailer assisted a C&I customer to obtain a better price by advocating on its behalf. In commenting on this transaction, the pipeline operator stated in its internal memo that reducing the tariff of the end-customer in this way was in line with its focus on "becoming a customer enabler".

In addition to these examples, the ACCC has identified a number of instances of larger C&I gas users having negotiated substantial discounts from the standing price or from the prices they were previously required to pay. The ACCC has, however, also identified some instances of smaller C&I gas users that have been unable to negotiate the same or similar deals as larger C&I gas users, and are therefore having to pay more for transportation.

Overall, while we have seen improvements in the negotiations between pipeline operators and shippers, prices generally remain high. This is discussed further below.

5.5. While some prices have fallen, transportation prices remain high

In the December 2017 and December 2018 interim reports, the ACCC reported on the prices paid for firm forward haul services by shippers in July 2017 and July 2018, respectively. To understand how prices have changed since the last Inquiry was completed, the period of analysis in this report has been extended back to July 2016. The scope of the analysis has also been expanded to include as available and interruptible transportation services (this includes APA's short-term firm, day-ahead and within-day services), as well as park and loan services.

The prices reported in this section are based on the prices payable under invoices and the standing prices[195] published by pipeline operators. Note that the prices paid by individual shippers may vary due to differences in key commercial terms, such as load factor, capacity commitments, service flexibility, contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement) and whether services are provided across a number of pipelines. Box 5.3 provides further detail on our approach to reporting on the prices payable by shippers.

Box 5.3: Approach to reporting prices

The following applies to the prices reported in this section.

- Prices have been sourced from invoices issued for July in all years (2016-2018) except the current year, where prices have been obtained from invoices issued for January. Prices have been analysed for invoices issued under GTAs entered into for a term of one month or longer.
- Where relevant, the prices reported for some pipelines include the prices payable for other services that are required to use that pipeline, such as compression in the case of the SWQP and the nitrogen removal service in the case of the NGP.
- On some pipelines, prices are charged on a $/GJ/km or a $/GJ/annum basis. In these cases, prices have been converted to a $/GJ measure using the appropriate conversion factor.
- The term 'maximum' is used in the charts in this section to refer to the highest price paid by shippers in the relevant year, while the term 'minimum' is used to refer to the lowest price paid in the relevant year. The term 'new prices' is used to refer to prices payable

194 Under these arrangements, the transportation costs are charged to a retailer and passed through to a shipper, rather than there being a direct contract between the pipeline operator and the C&I customer.

195 Throughout this section the term 'standing prices' is used to refer to the standing prices required to be published for pipelines subject to Part 23, 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. It also includes other prices published by pipeline operators, such as APA's multi-asset prices.

under contracts and variations negotiated since 1 August 2017.

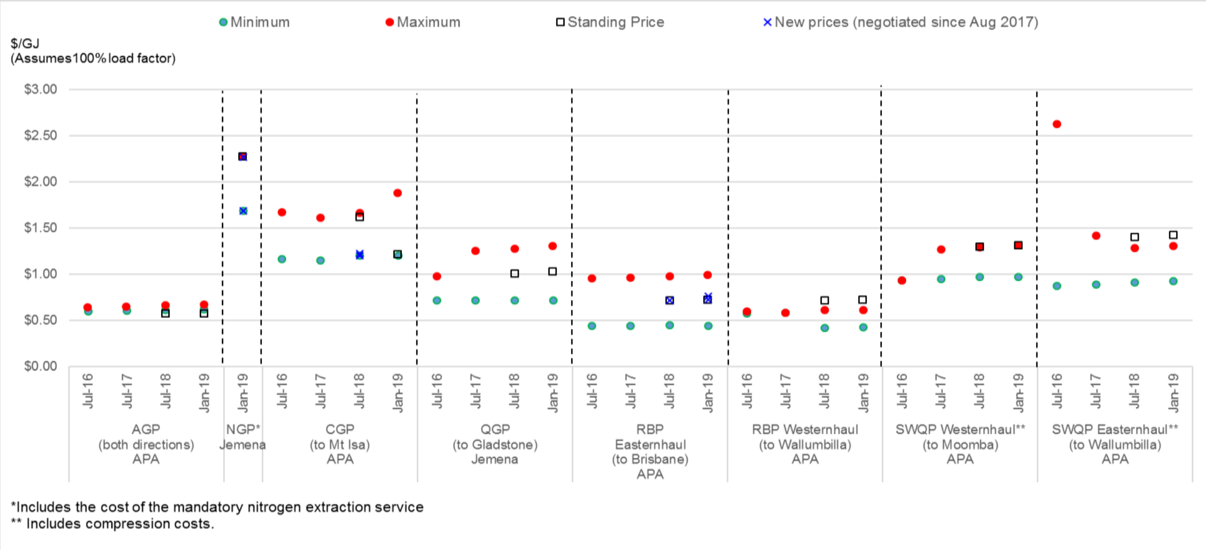
- Firm forward haul services:
  - Some firm forward haul services are based on a capacity charge only (i.e. $/GJ of MDQ) while others are based on a throughput charge ($/GJ) or a combination of the two. In the latter two cases, the prices have been converted to a $/GJ of MDQ measure, assuming a 100 per cent load factor (i.e. assuming the shipper utilises all the capacity it has contracted).
  - The prices reported for firm forward haul services are generally reported for the full length of the pipeline. It is worth noting though that a number of pipelines (for example, the MAPS, the PCA and RBP) charge the same price for firm forward haul services irrespective of the distance transported ('postage stamp pricing'). In these cases, the prices presented in the charts also apply to other locations on the pipeline mainline.
- As available and interruptible services:
  - The prices payable for as available and interruptible transportation services, and park and loan services have been included even when the quantity supplied in that month is zero. The prices reported for these services therefore represent the prices that would be paid under the shipper's GTA if the services had been supplied.
  - APA's short-term firm, day-ahead firm, within-day services are included in the as available services category given the nature of the services and approach to pricing. APA's new interruptible service, which is only available when a pipeline is fully contracted, is also included in the as available and interruptible services category.

5.5.1. Firm forward haul prices are falling on some pipelines and rising on others

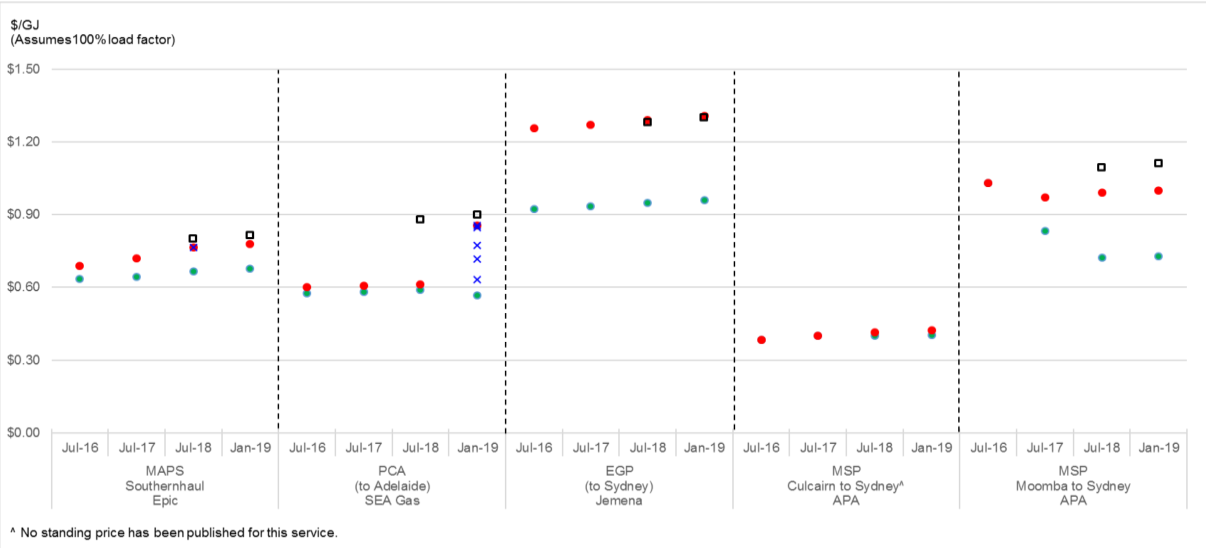
Chart 5.2 shows the minimum and maximum prices payable by shippers for firm forward haul services between July 2016 and January 2019 on key pipelines in Queensland and the Northern Territory (Northern Pipelines) and the Southern States (Southern Pipelines). For 2018 and 2019, the chart also shows the prices payable under more recently negotiated contracts and variations, and pipeline operators' standing prices.

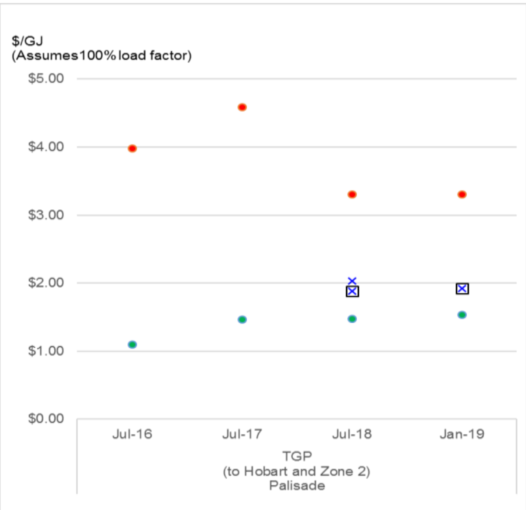
Chart 5.2: Firm forward haul transportation charges

Northern Pipelines



Southern Pipelines





Note: In prior reports the TGP prices were just reported between Longford and Hobart, but in this chart the prices reflect all the prices payable between Longford and Zone 2.

As chart 5.2 shows, the prices payable on a number of pipelines have remained relatively stable over the period (for example, AGP, RBP, SWQP and EGP), while others have experienced more significant changes (for example, the TGP, CGP, PCA and MAPS).

On those pipelines where prices have remained relatively stable, there has been limited contracting activity. The prices on these pipelines have tended therefore just to increase in line with inflation. On other pipelines, where there has been a greater level of contracting activity (as indicated by the blue crosses in the chart), prices have been subject to a greater degree of variability and the spread between the minimum and maximum prices has, with the exception of one pipeline, tended to increase.

The exception is the TGP, where the spread of prices for firm forward haul services has narrowed from $1.46–$4.59/GJ in July 2017 to $1.53–$3.30/GJ in January 2019. The reduced spread follows the arbitration between TGP and AETV Pty Ltd in early 2018 (discussed further in section 6.5), which resulted in a number of other shippers also being able to negotiate lower prices. In one case, a shipper was able to negotiate a 58 per cent reduction in their transportation charge.

In a similar manner to the TGP, the prices payable under new contracts and variations on the CGP have fallen significantly over the past two years. In one case, the shipper was able to negotiate a 24 per cent reduction to their transportation charge. This reduction is similar in scale to the reduction in standing price that occurred in the second half of 2018, with the standing price falling from $1.62/GJ to $1.21/GJ. As noted in section 5.4, this reduction has reportedly occurred in response to competition from the NGP for supply to Mt Isa. While some shippers may have benefited from the entry of the NGP, there are a number of C&I gas users that continue to pay relatively high prices on the CGP, with one shipper paying as much as $1.88/GJ in 2019. This is 55 per cent higher than the standing price.

In contrast to the TGP and CGP, prices have increased significantly on the PCA between July 2018 and January 2019 following the expiration of a number of foundation contracts. The prices agreed to under more recently negotiated contracts range from $0.63/GJ to $0.86/GJ, with the upper end of this range being 39 per cent higher than the prices that were paid under the foundation contracts in 2018. The magnitude of the increase is surprising, so too is the breadth of the range of prices that shippers have agreed to pay under the new contracts, given the contracts were negotiated over a similar period of time. While it is possible that some of this price differential could be attributed to differences in contract length and other key terms and conditions, we would not expect this to account for the entire difference.

Prices on the MAPS have also increased over the period, albeit to a lesser extent than on the PCA. The prices agreed under newer contracts on the MAPS have been at the upper end of the range appearing in chart 5.2 (i.e. $0.7781 in 2019), which while lower than the maximum price now payable on the PCA, is still high.

The price increases observed on the PCA and MAPS are noteworthy because, while one might expect competition between the two pipelines to impose a constraint on their owners' behaviour, it is clear from this review that competition between the two is not as effective in driving prices down to a cost-reflective level as might be expected. This observation is consistent with one of findings of the ACCC's 2015 Inquiry, which was that competition between pipelines did not appear to be posing a constraint on prices charged by pipeline operators.[196]

Finally, chart 5.2 shows that the standing prices published by the operators of most Part 23 pipelines (i.e. the SWQP, MAPS, PCA, EGP and MSP) continue to act in a similar manner to a price ceiling, with shippers having been able to negotiate lower prices in recent contracts.

196 ACCC, Inquiry into the east coast gas market, April 2016, pp. 97–99.

The reference tariffs set by the AER for the AGP and RBP (eastern haul), on the other hand, tend to act more like a price floor, with a number of shippers agreeing to pay more than these tariffs. While not shown in chart 5.2, the standing price for the bundled firm forward haul service between Wallumbilla and Wilton is currently $2/GJ. This standing price is set at a 17 per cent discount to the standing prices for the SWQP and MSP, which sum to $2.42/GJ.[197]

5.5.2. The incidence of excessive as available and interruptible prices has decreased

Chart 5.3 shows the minimum and maximum prices payable by shippers for as available and interruptible transportation services between July 2016 and January 2019, as well as the prices agreed in more recently negotiated contracts on Northern and Southern pipelines.

In a similar manner to firm forward haul services, the prices payable for as available and interruptible transportation services on those pipelines that have experienced limited contracting activity over the period have tended to just increase in line with inflation (for example, the EGP, MAPS, PCA and MSP (Culcairn to Sydney)).

In contrast to these pipelines, the prices payable for these services on pipelines that have experienced a greater level of contracting activity (for example, the CGP, the MSP (Moomba to Sydney) and SWQP) have been subject to a greater degree of variability. This has resulted in the spread of prices on these pipelines widening. The increase in the spread of prices has been most pronounced on the CGP, with the prices payable for these services in January 2019 ranging from $0.91 to $2.34/GJ. The spread of prices on the MSP (Moomba to Sydney) is also quite large, currently ranging from $0.83 to $1.66/GJ.

The variation in both of these cases could reflect the introduction of APA's new suite of shorter term services, the prices of which differ depending on the term of the service and the priority of the service (i.e. less than 12 months, day-ahead, within-day and interruptible). The extent of this variation can be seen in the standing prices for each of these services, with the prices for short-term firm, day-ahead and within-day services ranging from 120-150 per cent of the long-term firm price. APA's interruptible rate, on the other hand, which is only available when the pipeline is fully contracted, is 75 per cent of the long-term firm price. APA's decision to introduce this new suite of short-term services appears to be designed to take advantage of the changing nature of the demand for services as highlighted in section 5.3.

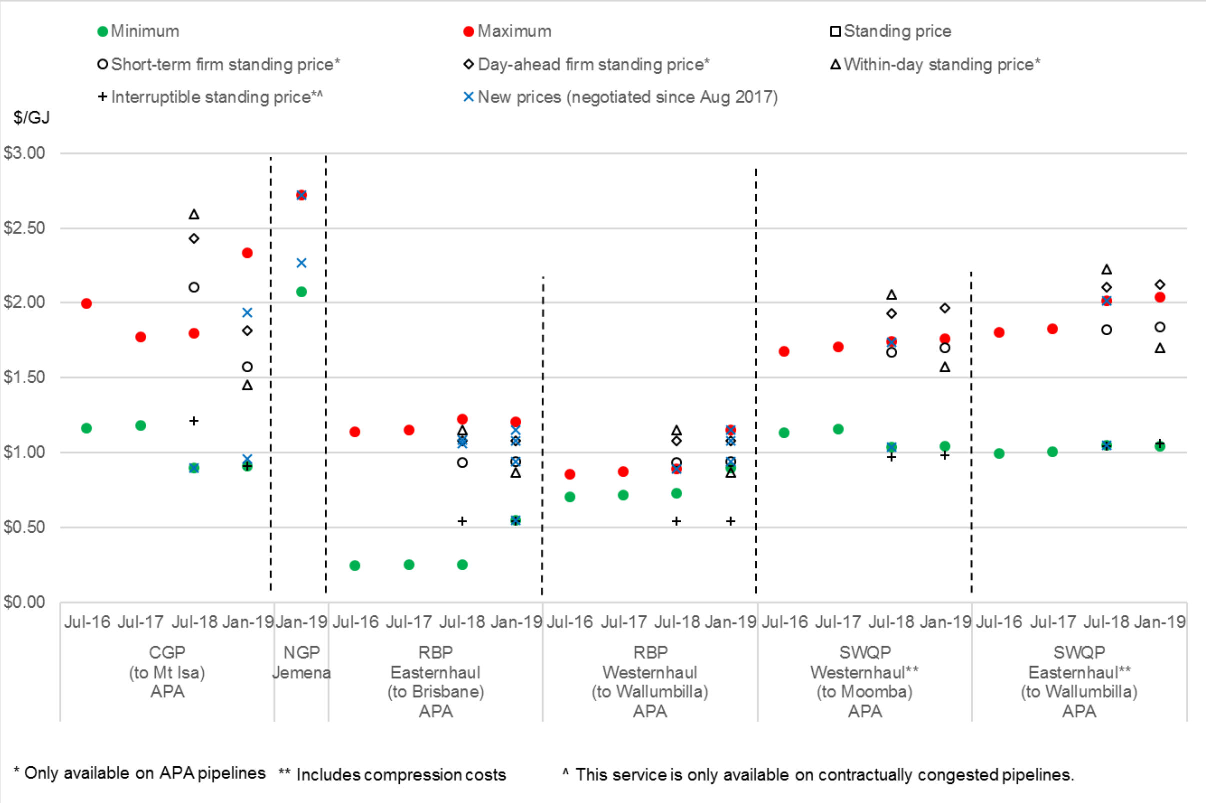
Between July 2016 and January 2019 the number of shippers with access to as available and interruptible services has increased, in many cases doubling in number. This is particularly pronounced on the SWQP, which has seen the number of shippers using western haul and eastern haul as available or interruptible transportation services quadruple. The increase in number of shippers using these services is not surprising given that this is a key link between Queensland and the Southern States, and that APA is unable to offer firm services because the capacity of the Wallumbilla compression facility is fully contracted.[198]

197 APA website accessed July 2019: https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/ and https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/offers/.

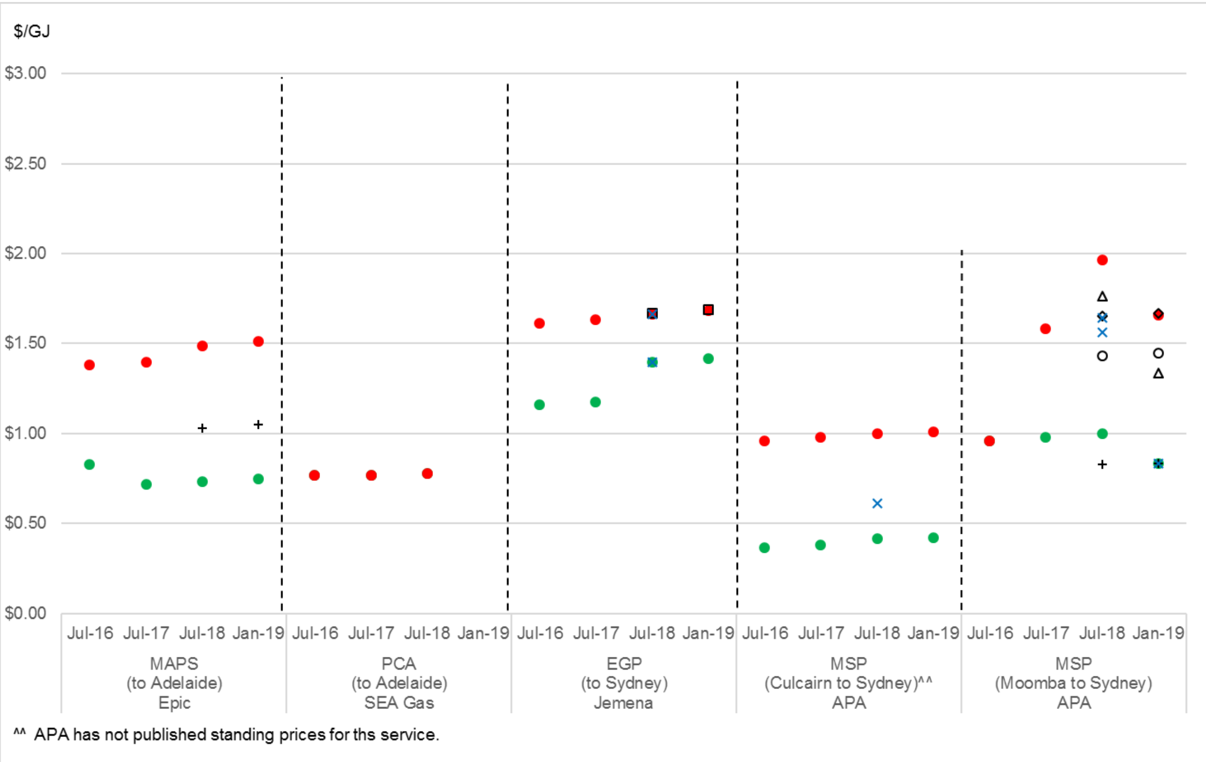
198 APA, *36 months uncontracted capacity outlook*, https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/moomba-sydney-pipeline/, accessed 18 June 2019.

Chart 5.3: As available and interruptible transportation charges

Northern pipelines



Southern pipelines



Notes: This chart excludes some pipelines because they either do not offer as available or interruptible transportation services, or they only provide the service to one shipper.

The ACCC's 2015 inquiry found that some pipeline operators were charging excessive prices for as available and interruptible transportation services, with some shippers having to pay 185 to 350 per cent of the firm forward haul price for these services.[199] The incidence of this appears to have fallen in the intervening period, with most shippers now paying between 110–160 per cent of the firm transportation tariff for these services, the majority of whom are paying between 110–130 per cent.

We have also identified some instances of shippers on APA pipelines that have entered into contracts for interruptible services where the prices are set at 75 per cent of the firm forward haul charge, although as noted above, these prices are only available when a pipeline is fully contracted. APA has also entered into a contract for a short-term firm service where the price was around the same level as the standing price. Jemena is also providing as available services to some shippers at the same price as the firm forward haul service.[200]

While there have been some positive developments in this area, there are a small number of shippers that are still paying over 200 per cent of the firm forward haul tariff for as available or interruptible transportation services on various pipelines. While these prices may reflect older contracts or GTA specific conditions, they are very high and the ACCC intends to monitor whether they are reduced in subsequent negotiations.

The ACCC expects that the capacity trading reforms will start having a greater influence on the prices payable for these services. As the GMRG has previously observed, one of the key objectives of these reforms is to facilitate more secondary trading amongst shippers. This will limit the reliance that shippers have to place on procuring as available and interruptible services from pipeline operators and, in so doing, pose more of a constraint on the prices charged for these services.[201] The adoption of a zero reserve price for the day-ahead auction is also intended to impose more of a constraint on the prices pipeline operators charge for day-ahead capacity.[202] As noted in section 5.3, the ACCC intends to conduct a closer review of the impact of the capacity trading reforms on shipper and pipeline operator behaviour in the latter half of this year.

Chart 5.3 also shows the standing prices published by pipeline operators in 2018 and 2019 for as available and interruptible transportation services. As noted above, APA's standing prices for interruptible, short-term firm, day-ahead and within day services range from 75-150 per cent of the firm forward haul standing price, while other pipeline operators' standing prices are around 130 per cent of the firm forward haul standing price.

In contrast to firm forward haul services, the standing prices published by the operators of Part 23 pipelines are, in some cases, operating like a price ceiling (i.e. the QGP, EGP and MSP (Culcairn to Sydney)), while in other cases they are falling between the minimum and maximum prices payable by shippers (i.e. the MAPS and SWQP). Further, chart 5.3 shows:

- the CGP standing prices have fallen by around 25 per cent between July 2018 and January 2019, which has reportedly occurred in response to potential new competing supply to Mt Isa via the NGP (see section 5.4), and
- APA's standing prices for the within-day service have fallen from 160 per cent of the long-term firm transportation price to 120 per cent in response to the change in priority of this service that followed the implementation of the day-ahead auction.

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199 ACCC, *Inquiry into the east coast gas market*, April 2016, chapter 6, pp. 108–110.

200 APA, *Current tariffs and terms*, https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/; Jemena, *Northern Gas Pipeline*, https://jemena.com.au/pipelines/northern-gas-pipeline.

201 GMRG, *Capacity Trading Reform Package: Final legal and regulatory framework—Explanatory Note*, 22 November 2018, pp. 16–18.

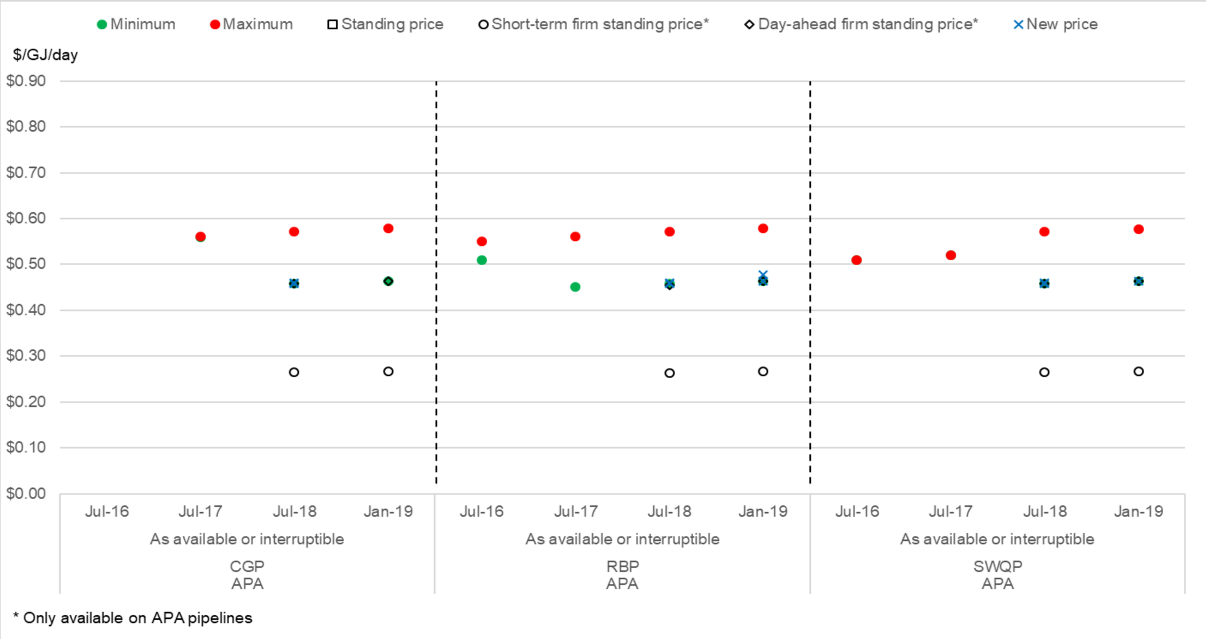
202 ibid, p. 17.

5.5.3. Park and loan prices vary markedly across pipelines

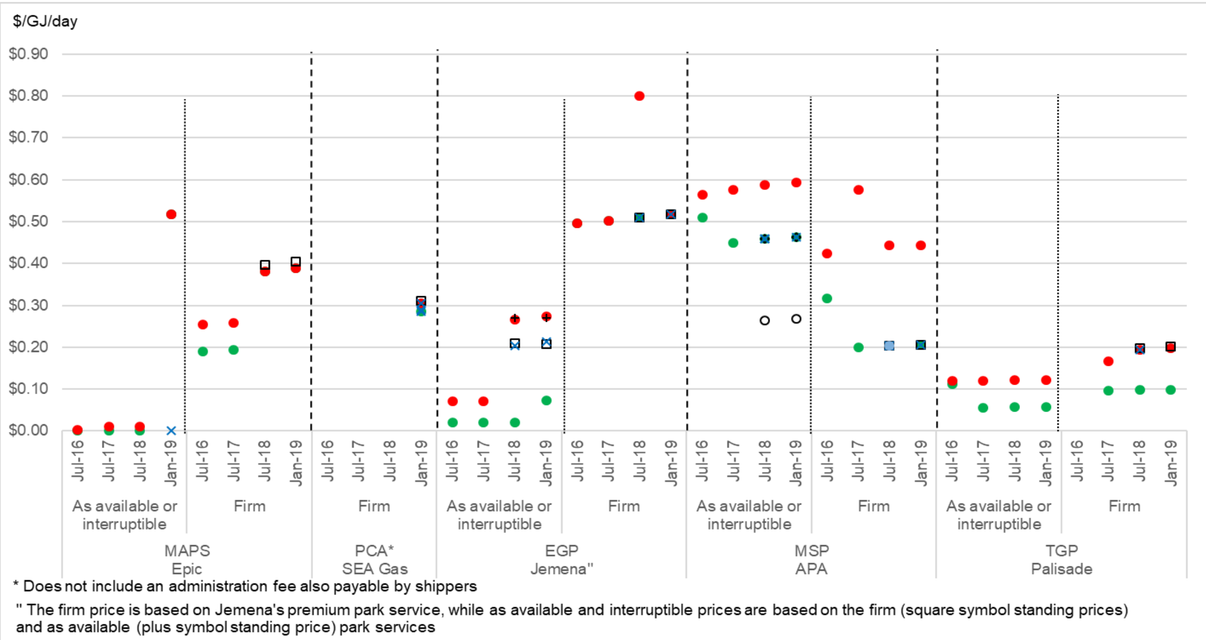
Chart 5.4 shows the minimum and maximum prices payable by shippers for park and loan services (both firm and as available or interruptible services) between July 2016 and January 2019, as well as the prices agreed in more recently negotiated contracts on Northern and Southern pipelines.

Chart 5.4: Park and loan service charges

Northern pipelines



Southern pipelines



Notes: This chart excludes some pipelines because they either do not offer as available or interruptible transportation services, or they only provide the service to one shipper.

Like firm forward haul and as available transportation services, the prices payable for park and loan services on pipelines that have experienced limited contracting activity have tended to increase in line with inflation, while the spread of prices on pipelines that have been subject to a greater level of contracting activity has increased.

As chart 5.4 shows, the prices payable for park and loan services vary considerably across pipelines, with the prices payable in January 2019 for firm services ranging from $0.10 to $0.52/GJ, while the prices payable for as available and interruptible services ranging from $0.06 to $0.59/GJ. The variation in prices is interesting because, while most pipeline operators claim that the price for park services is based on the opportunity cost of selling these services relative to a firm forward haul service (i.e. so the price is related to the firm forward haul price payable on the pipeline),[203] APA has adopted a single price for these services across all of its pipelines. The adoption of a single price suggests that there may be more of a market-wide price for storage services.

Chart 5.4 also shows the standing prices published by pipeline operators in 2018 and 2019 for park and loan services. As this chart shows, standing prices appear to be acting like a price ceiling on a number of pipelines, including the MAPS, PCA, EGP and TGP. In contrast to these pipelines, APA's standing prices for park and loan services are below the prices it has historically charged for these services. The ACCC understands that APA decided to reduce the standing prices for these services following "market feedback" that the prices for these services were "too high" and to ensure consistent pricing for imbalance and park and loan services across APA's pipelines.

5.5.4. Summary

As the preceding discussion highlights, the prices payable under existing GTAs for firm forward haul services, as available and interruptible transportation services and park and loan services have tended to just increase in line with inflation over the last two and a half years. For newer contracts and variations, the trend is less clear, with the prices for services on some pipelines having fallen significantly (for example, TGP and CGP firm forward haul prices), and others experiencing a material increase (for example, the PCA firm forward haul, MAPS firm forward haul and park, the EGP as available transport and park prices and some services on the RBP and MSP). The price increases observed on these pipelines is concerning, particularly given the evidence of monopoly pricing that was found in the ACCC's 2015 Inquiry.[204] The ACCC will continue to examine the contracting activities of pipeline operators and consider the cost reflectivity of prices.

While prices have increased on a number of pipelines, the incidence of excessive as available and interruptible transportation prices has fallen, which is a positive development. If the capacity trading reforms are successful, then the ACCC would expect to see further reductions in these prices over time. With shippers now able to use the capacity trading platform to compete with pipeline operators to supply park products, it is possible that these reforms may also place downward pressure on the prices payable for park and loan services.

The other positive outcomes observed in this review is that a number of larger C&I gas users appear to have been able to negotiate substantial discounts from either the standing price, or the prices they have previously paid for services in the last two years. The same discounts do not, however, appear to have been extended to smaller C&I gas users (see section 5.4). It would also appear that a number of C&I gas users with older GTAs are paying prices that are towards the upper end of the range on some pipelines. The ACCC will continue to monitor the prices offered to C&I gas users.

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203 See for example, Jemena, Eastern Gas Pipeline Transportation Services and Pricing Methodology and SEA Gas, Pricing Methodology, 4 February 2019.

204 ACCC, Inquiry into the east coast gas market, April 2016, Chapter 6.

6. Review of the operation of Part 23 of the National Gas Rules

6.1. Key points

- The information disclosure and arbitration framework, as set out in Chapter 6A of the NGL and Part 23 of the NGR, was introduced in August 2017 to reduce the information asymmetry and imbalance in bargaining power shippers can face when negotiating with non-scheme pipeline operators
- Two years on from commencement, the ACCC has reviewed whether key elements of the framework are working as intended and the effect its introduction has had on pipeline investment.
- Since the introduction of Part 23, 126 GTAs have been negotiated or varied on major transmission pipelines in the East Coast Gas Market that are subject to Part 23, with just one negotiation proceeding to arbitration. While the contracting environment has improved and some shippers have been able to secure lower prices, the ACCC is concerned that some pipeline operators do not appear to be taking the information disclosure obligations under Part 23 seriously and are continuing to exploit information asymmetries to the detriment of shippers.
- The ACCC has, for example, identified a number of instances where pipeline operators are not publishing standing prices for all the services they offer, as required by the NGR. The pricing methodologies published by most pipeline operators are also inadequate and do not allow shippers to determine whether the standing prices reflect the application of the methodology, or to assess the reasonableness of these prices.
- The ACCC also found that the weighted average prices (WAPs) published by pipeline operators may not be achieving the stated objective of this disclosure requirement because they do not provide a good representation of the prices actually paid by shippers and in some cases are not directly comparable to the pipeline operators' standing prices. Shippers may not therefore be able to rely on this information to assess the reasonableness of an offer by reference to what other shippers are paying.
- Pipeline operators are also required to publish an estimate of the pipeline's recovered capital value (RCV), which is meant to provide an indication of the extent to which the costs incurred in constructing and augmenting the pipeline have been recovered. The ACCC has found that the RCVs of a sample of seven pipelines have been overstated by up to 45 per cent (with over half of the sample being overstated by more than 20 per cent) as a result of errors and/or the adoption of a range of inflationary measures. The values have been further overstated by the adoption of relatively high rates of return.
- Our review of pipeline operators' internal documents and other access request and offer information indicates that the access request and negotiation provisions in Part 23 are largely working as intended. However, it would appear that shipper requests are often being treated as 'preliminary enquiries' rather than formal access requests, enabling pipeline operators to avoid some of the requirements in Part 23 around responding to access requests and negotiations. This is a potential limitation in the access request process.
- The review also revealed that some shippers are using the threat of arbitration in negotiations. A concern has, however, been raised with the ACCC that pipeline operators may view the threat as less credible when it involves a smaller shipper, which is a possible weakness in the framework.
- The issues identified in this review have the potential to undermine the efficacy and intent of Part 23. The ACCC therefore recommends a range of improvements to Part 23 to

pose more of a constraint on pipeline operators and to improve the quality, accessibility and reliability of the reported information so shippers can have more informed negotiations with pipeline operators. These improvements include changes to:

    - the AER's Financial Reporting Guideline for Non-scheme Pipelines (Guideline), and
    - the NGR that should be considered as part of the Energy Council's gas pipeline regulation reform regulation impact statement (RIS) process.

  The ACCC will also refer a number of matters to the AER for further investigation in respect of compliance with reporting obligations under Part 23.

- The ACCC will continue to monitor the quality of the information reported by pipeline operators and the timeliness and outcomes of negotiations on pipelines.

6.2. Introduction

As noted in the preceding chapter, the ACCC's 2015 Inquiry found that while pipeline operators had been responding well to the changes underway in the market, there was evidence that a large number of pipelines were engaging in monopoly pricing.[205] It also found that the lack of publicly available pricing and financial information was hindering the ability of shippers to negotiate effectively with pipeline operators and to readily identify any exercise of market power.[206]

In response to these findings, the Energy Council directed Dr Vertigan to carry out an *Examination of the current test for the regulation of gas pipelines.* In a similar manner to the ACCC, Dr Vertigan found that pipeline operators have market power and that the exercise of this power was resulting in inefficient outcomes. Rather than amend the test for regulation, Dr Vertigan recommended in late 2016 that steps be taken to reduce the information asymmetry and imbalance in bargaining power shippers can face when negotiating with non-scheme pipeline operators.[207] Eight months later, the Energy Council implemented a new information disclosure and arbitration framework for non-scheme pipelines.[208]

This new regulatory framework is set out in Chapter 6A of the NGL and Part 23 of the NGR (for ease of reference this framework is referred to as 'Part 23' in this chapter). The objective of the framework is to:[209]

> *"…facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which … is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market".*

The key elements of this framework include:

- **An information disclosure regime** that requires pipeline operators to publish a user access guide and the following information to enable shippers to carry out a high level assessment of the reasonableness of the pipeline operator's offer:
    - the standing terms for each service (which includes the standing price and standard terms and conditions) and the method used to calculate the standing price
    - the weighted average prices (WAPs) paid by shippers for pipeline services

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

206 ACCC, Inquiry into the east coast gas market, April 2016, Chapter 6.

207 Vertigan, M, Examination of the current test for the regulation of gas pipelines, 14 December 2016, pp. 9–10.

208 Vertigan, M, Examination of the current test for the regulation of gas pipelines, 14 December 2016.

209 NGR, r. 546.

  - the financial information specified in the AER's Guideline, which, amongst other things, provides for the publication of a pipeline's RCV, and
  - a range of other information about the pipeline, pipeline services, service usage and service availability.

  If a shipper decides to seek access, further information can be obtained from pipeline operators in the negotiation stage.

- **An access request and negotiation framework** that is designed to facilitate timely and effective commercial negotiations and minimise the reliance on arbitration. It involves two stages:
  - **Access request and response stage**: In this stage, the shipper makes an access request to the pipeline operator (or it may make a preliminary enquiry before submitting a formal access request) and the pipeline operator responds. To facilitate this process, Part 23 sets out the requirements for shippers making an access request and for pipeline operators responding to an access request, including the timeframes in which they must respond.
  - **Commercial negotiation stage**: In this stage, the shipper and pipeline operator negotiate on the terms and conditions of access, which may be informed by further information exchanges. To facilitate this process, Part 23 requires the parties to disclose all the information that they would seek to rely on in an arbitration to demonstrate the pipeline's offer or the shipper's counter offer is reasonable.
- **An arbitration mechanism** that can be triggered by either party if agreement cannot be reached during negotiations. To enable disputes to be resolved in a timely manner, Part 23 requires the arbitration to be conducted using the information exchanged during negotiations and to be completed within 50 business days (or 90 business days if the parties agree to an extension).[210] Part 23 also sets out the cost-based pricing and other principles that an arbitrator must have regard to when determining access disputes.

A pipeline operator can apply to the AER for a full exemption from Part 23 if it is not providing third party access.[211] Exemptions from some or all of the information disclosure requirements can also be sought by pipeline operators for pipelines that only supply a single user, or fall below a size threshold specified in the NGR.[212] Non-scheme pipelines that have been granted an **exemption** are identified in a public register on the **AER's** website.[213]

As figure 5.1 in chapter 5 shows, a large number of transmission pipelines are now subject to Part 23, including some of the major links in the East Coast Gas Market such as: the SWQP, MSP, EGP, MAPS, PCA, TGP, QGP, DDP, and BWP. Together, these pipelines are used by over 40 shippers[214] with interests in production, retail, GPG and LNG exports, as well as a range of small and large C&I gas users.

With Part 23 having been in operation for almost two years, it is relevant to consider whether the key elements of the framework are working as intended and the effect that its introduction has had on negotiations, pipeline investment and overall market transparency and operation. The ACCC has therefore used its compulsory information gathering powers to seek information from the operators of non-exempt non-scheme pipelines in the East

210 NGR, r. 572.

211 NGR, r. 585.

212 There are three categories of non-scheme pipeline that are exempt from part or all of the information disclosure under r. 585 of the NGR: (1) pipelines that do not offer third party access are exempt from the information disclosure and arbitration provisions; (2) pipelines that only have a single user are exempt from the upfront information disclosure; and (3) pipelines that have an average daily injection for the preceding 24 months of less than 10TJ/day are exempt from the information provision requirements except the requirements to publish details of the pipeline and services offered.

213 AER, *Public register of non-scheme pipeline exemptions*, https://www.aer.gov.au/networks-pipelines/non-scheme-pipelines/public-register-of-non-scheme-pipeline-exemptions.

214 Information on shippers obtained from the Natural Gas Services Bulletin Board. AEMO, *BB Shipper Lists*, https://www.aemo.com.au/Gas/Gas-Bulletin-Board/Other-Reports/BB-Shippers.

Coast Gas Market[215] on the key pieces of information they are required to report. The ACCC also sought information from pipeline operators on the negotiations that have recently taken place, and the impact that Part 23 has had on investment decisions.

The level of cooperation and timeliness of the provision of information by pipeline operators was disappointing. Notwithstanding the ACCC's compulsory information gathering powers, some pipeline operators requested multiple extensions, did not comply with the specified timeframes, inappropriately redacted documents and/or were reluctant to provide the requested information at all.

The remainder of this chapter sets out the results of our review. It also sets out our recommendations on how Part 23 could be improved, many of which we suggest be considered by the Senior Committee of Officials (SCO) through the gas pipeline regulation reform RIS.

6.3. Pipeline operators do not appear to be taking the information disclosure obligations seriously

The effectiveness of Part 23 is critically dependent on the provision of accurate information by pipeline operators that is accessible to shippers as an input to commercial negotiations. This is reflected in the purpose of the information disclosure regime, which was described by the Gas Market Reform Group (GMRG) as being to:

> *"…allow shippers to make an informed decision about whether to seek access and to carry out a high-level assessment of whether the pipeline operator's standing offers are reasonable, having regard to the pipeline's financial reports, the weighted average price per service and information published by the pipeline operator on how the standing offers for each of the services offered by the pipeline have been calculated"*[216]

> *"…reduce the information asymmetry shippers can face in negotiations and, in so doing, facilitate more timely and effective negotiations".*[217]

Given the importance of this information, we have conducted a detailed review of the standing prices, pricing methodologies, WAPs and the RCVs published by non-exempt non-scheme pipelines. The results of our review are set out below.

6.3.1. There are gaps in the standing prices published by pipeline operators

Operators of non-exempt non-scheme pipelines are required to publish the standing terms for each pipeline service on the pipeline, which includes both the standing price and the standard terms and conditions applicable to the pipeline service.[218]

In a similar manner to our April 2018 interim report, we have compared the standing prices for firm forward haul services published for the major non-exempt non-scheme pipelines in the East Coast Gas Market with the minimum and maximum prices paid by shippers for firm forward haul services in January 2019.[219] As chart 5.2 in the preceding chapter shows, the standing prices for firm forward haul services continue to be higher than the prices actually paid by most shippers, including the prices negotiated since 1 August 2017 when Part 23 commenced. It appears that standing prices are still viewed by pipeline operators as a price ceiling and that shippers should be able to negotiate lower prices.

215 While the ACCC's review has focused on the East Coast Gas Market, the issues identified in this chapter are also expected to apply in Western Australia given the common ownership of some pipelines.
216 GMRG, *Explanatory Note: Gas Pipeline Information Disclosure and Arbitration Framework*, 2 August 2017, p. 6.
217 ibid p. 5.
218 NGR, r. 554.
219 The term "maximum" refers to the highest price paid by shippers, while the term 'minimum' is used to refer to the lowest price paid.

As part of this review, we also examined whether standing prices are published for all of the services offered by pipeline operators, as is required by rule 554 of the NGR. We found a number of cases where pipeline operators had not published a standing price for some of the services they provide. The ACCC will refer these cases to the AER, who is responsible for monitoring and enforcing compliance with the Part 23 obligations.

In addition to these gaps, we understand that some shippers have concerns with the exemptions that single user pipelines and pipelines that fall below the size threshold are currently able to obtain from the requirement to publish standing prices. This issue was raised in the ACCC-GMRG joint report on measures to improve the transparency of the gas market.[220] As we noted in that report, while information on standing prices and standard terms and conditions can be obtained by prospective shippers in negotiations, there could be value in requiring currently exempt pipelines to publish this information on their website, so that prospective shippers can more readily assess whether to seek access to the pipeline. The other benefit of publishing this information is that it would provide those gas users that procure gas from a retailer greater transparency of the costs likely to be incurred by retailers, which are usually charged to customers on a pass-through basis.[221]

The costs of extending this reporting obligation to currently exempt pipelines is expected to be relatively low. The ACCC therefore recommends that, as part of the gas pipeline regulation reform RIS, SCO consider removing the exemption that single user pipelines and pipelines with annual average gas flows of <10 TJ/day currently have from the obligation to publish standing prices and the standard terms and conditions of access on their website.

6.3.2. Most pipeline operators' pricing methodologies do not allow shippers to verify how prices are calculated or to assess their reasonableness

Operators of non-exempt non-scheme pipelines are required to publish the methodology used to calculate the standing price and "sufficient information to enable prospective users to understand how the standing price reflects the application of the methodology".[222]

Table 6.1 provides a summary of the firm forward haul pricing methodologies that have been published by non-exempt non-scheme pipelines.

220 ACCC and GMRG, *Joint recommendations: Measures to improve the transparency of the gas market*, December 2018, p. 34.

221 While standing prices may be higher than what the retailer is actually paying, the publication of this information would provide users with a point of reference for their negotiations with retailers.

222 NGR, r. 554.

Table 6.1: Summary of published pricing methodologies

Operator	Pipeline	Firm forward haul services
APA[223]	**SWQP**	Standing price for transport-only SWQP tariff based on foundation agreement entered into in 2009, escalated in accordance with that contract. Standing price for SWQP Easternhaul 'compression required' service based on SWQP transport-only standing tariff plus the base Moomba pressure tariff from the foundation shipper contract entered into in 2012 escalated in accordance with the terms of that contract. Standing price for SWQP Westernhaul 'compression required' service based on SWQP transport-only standing tariff plus the MDQ-weighted average of two foundation shipper contracts for pressure services entered into in 2010 and 2009 escalated in accordance with those contracts.
	MSP	Standing price based on the published tariff, which has moved with CPI since the covered portion became light regulated in 2008, with the exception of adjustment to enable capacity expansion in the period 2009 to 2014. The expansion tariff adjustment was an initial 5c/GJ increase in the full-haul tariff, followed by five annual increments of 1c/GJ.
	SESA	Standing price based on the annual charge in a foundation agreement entered into in 2007, divided by the nameplate capacity of the pipeline and escalated in accordance with the terms of that contract.
	BWP	Standing price based on a foundation agreement entered into in 2010 escalated in accordance with the terms of that contract.
	WGP	Standing price based on the annual capital charge in a US$ denominated foundation contract that was entered into in 2015, multiplied by A$/US$ exchange rate as at 24 January 2018, plus annual operating costs, divided by nameplate capacity. The annual capital charge is escalated annually by the US Producer Price Index (PPI), then by 75% of the difference between the US PPI and US CPI.
Epic[224]	**MAPS**	Standing price calculated using a "building block methodology" which calculates a "revenue requirement" for each year. As the standing price is offered in respect of a five year term, a revenue requirement for each of the five-year period commencing July 2017 and ending June 2022 has been calculated. This revenue requirement is then divided by the forecast demand, which gives a per GJ/day tariff.
Jemena	**EGP**[225]	Standing price based on price in place at the time the pipeline was commissioned ($0.30 for zone 1, $0.65 for zone 2 and $0.86 for

223 Note that the methodologies in Table 6.1 are published by APA as a "tariff derivation" on its website, see https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/. APA also publishes a pricing methodology which describes the factors considered in setting standing prices for its pipelines: see APA, *APA Pricing Methodology*, February 2018, https://www.apa.com.au/globalassets/documents/info/general/apa-pricing-methodology.pdf.

224 Epic Energy, *Moomba to Adelaide Pipeline System: Standing price information,* 30 January 2018, https://www.epicenergy.com.au/gmrg/Standing_Terms_Methodology.pdf.

		zone 3 in relevant base year of 1998), which has been escalated by 75 per cent of the annual change in CPI (calculated using the December quarter weighted average of eight capital cities index). The original tariff was set at levels to encourage pipeline utilisation, as the EGP was initially not fully contracted.
	QGP[226]	Standing price based on the reference tariff in place at the time the pipeline was regulated, which has been adjusted for annual inflation. The reference tariff was originally set to comply with cost of service rules governing the regulation of gas pipelines. Regulation was revoked in 2008.
	VicHub [227]	Standing price based on tariff in place in 2008, which has been adjusted by 75 per cent of annual change in CPI (Weighted average eight capital cities).
	DDP[228]	Standing prices for firm forward haul services determined following an analysis of: • Market dynamics and other considerations relevant in a workably competitive market. These considerations include pricing on competitor services, expected future demand for pipeline services, and delivery point flexibility; and • A cost-reflective exercise which forecast economic costs for each pipeline segment over a 5 to 10 year horizon and divided those forecast costs for each pipeline segment by forecast contracted demand for each segment to determine a $/GJ per day cost.
SEA Gas[229]	**PCA**[230]	Standing price based on cost-reflective approach. Revenue requirement determined using rates of return commensurate with the expected costs of raising equity and debt, cognisant of achieve commercially sustainable outcomes for SEA Gas and prospective users. The methodology is: • The opening asset value as at 1 July 2018 was estimated using historical data on initial construction costs, the amount of capital expenditure since commissioning, the return of capital recovered since commissioning and the value of pipeline assets disposed since commissioning. This determined an asset base of $435m (at 1 July 2018) (using a remaining pipeline life of 66.5 years from the original 80 years). • Using the asset base and incorporating 10-year forecast inputs plus a residual at the end of the 10 year forecasts, further modelling was performed to derive an Estimate Required Revenue (ERR) for each year. • Using the ERR and dividing by the available firm forward capacity (in GJ/day), the average tariff per year was determined.

225 Jemena, *Eastern Gas Pipeline: Standard service offering*, https://jemena.com.au/documents/pipeline/egp-transportation-services.aspx.
226 Jemena, *Queensland Gas Pipeline: Standard service offering*, 9 January 2018, https://jemena.com.au/documents/pipeline/qgp-transportation-services.aspx.
227 Jemena, *VicHub: Standing service offering*, https://jemena.com.au/documents/pipeline/vichub-transportation-services.aspx.
228 Jemena, *Darling Downs Pipeline: Standard service offering*, https://jemena.com.au/documents/pipeline/ddp-transportation-services.aspx.
229 SEA Gas, *Pricing Methodology*, 4 February 2019, https://seagas.com.au/app/uploads/2019/02/Pricing-Methodology-20190204.pdf.
230 At the time the documents were sought from pipeline operators, SEA Gas did not publish a standing price for the PCI. SEA Gas has subsequently published a standing price for the PCI.

	• The above range was then 'smoothed' to estimate a price path for each year of the forecast period.
TGP[231]	Standing price for firm forward haul Zone 1 and Zone 2 and as available services were subject to an arbitration with a final access determination made on 12 April 2018. Under that arbitration, the arbitrator used a cost based methodology and determined an asset value of $163.2 million using a "Modified Depreciated Actual Cost" (MDAC) approach. MDAC represents an indexed depreciated actual cost adjusted downwards to reflect the value of the assets used in the provision of transport services and excludes the value of the assets used in the provision of separate services such as High Priority Storage Services. Under the cost based methodology, a revenue requirement for firm forward haul services is determined by: • reference to the asset base of $163.2 million which represents an arbitrated allocation of assets having regard to the pipeline capacity required to meet the requirements of the foundation contracts that underpinned the development of the pipeline • applying a commercial rate of return to the asset base to produce a return on capital, using a 'vanilla' nominal Weighted Average Cost of Capital • making an allowance for the forecast operating, capital and maintenance costs of keeping the asset in service, and • making an allowance for the 'cost' of tax. The standing prices for firm forward haul services are the tariffs determined by the arbitrator, which are to be escalated annually. Counterparty creditworthiness and term will also come into consideration in relation to the application of these prices to a particular prospective shipper.

[231] TGP, *Part 23 User Access Guide: TGP*, 18 May 2018, p. 12, https://www.tasmaniangaspipeline.com.au/client-assets/Part%2023/20180531%20TGP%20User%20Access%20Guide.pdf.

As this table shows, a variety of pricing methodologies are currently being employed by pipeline operators, with some basing their prices on:

- cost-based methodologies (i.e. the PCA, MAPS and TGP)
- prices struck in foundation agreements (i.e. the SWQP, SESA, BWP and WGP)
- prices established when the pipeline was regulated (i.e. the QGP and the MSP)
- prices payable when the pipeline was commissioned or acquired (i.e. the EGP and VicHub), and/or
- other 'market based' factors (i.e. the DDP).

In the April 2018 interim report, we reviewed the pricing methodologies published by pipeline operators and found that some of the methodologies lacked sufficient detail to enable prospective shippers to understand how standing prices have been derived. In the intervening period some improvements appear to have been made to a number of the pricing methodologies. TGP, for example, has published more detail on the inputs used to calculate its firm forward haul standing price. APA has also changed its description of the method used to calculate the firm forward haul standing price for the MSP from what was a relatively vague description of the pricing methodology (i.e. "tariffs based on competitive energy supply options into Sydney and Victorian markets") to a more detailed description of how prices have changed since it was regulated (see table 6.1).

While some improvements have been made, it is still not clear that shippers could use the information published by pipeline operators to verify that the published methodology has actually been used to calculate these prices and to assess the reasonableness of the standing price.

As the information in table 6.1 reveals, with the exception of the pricing methodologies published for the EGP and VicHub, it is not possible to verify the calculation of the standing prices on any of the other pipelines using the information published by pipeline operators. This is because the pricing methodologies published by these pipeline operators do not contain:

- information on all of the input values that would be required to calculate the firm forward haul standing prices, or
- a pricing model or mathematical representation of the calculations used to calculate the firm forward haul standing prices.

The majority of methodologies tend instead to include a high-level description of the inputs used and a general description of how these inputs were used to calculate a standing price. The ACCC has therefore had recourse to its compulsory information gathering powers to obtain information from pipeline operators on how the standing prices have been calculated. In some cases, pipeline operators responded by providing detailed pricing models, while in other cases they provided a simple spreadsheet.

Using this information, we were able to verify that the pricing methodologies had been used to calculate nine of the 12 pipelines' standing prices. Of the remaining three pipelines, we were able to establish that the pricing methodology had been used to calculate the standing prices on two of the pipelines, but found some small discrepancies between the standing prices and the method (for example, due to errors in the description of the escalation mechanism). On the final pipeline, it was not possible to confirm that the pricing methodology had been used to calculate the standing price, because the methodology does not use a formulaic mathematical calculation.

This verification process took some time and we sought clarifications from a number of pipeline operators to better understand the pricing methodologies that they had employed and to verify that these methodologies had in fact been used. Given the challenges we encountered through this process, the ACCC has considered how the pricing methodologies could be improved so that shippers are better placed to determine whether the standing prices reflect the application of the methodology and to assess the reasonableness of these prices. In doing so, we have considered GMRG's original recommendation on this issue, which was that pipeline operators should be required to publish information on 'the pricing methodology and the inputs used to calculate the standing offers for each of services offered by the pipeline'.[232]

Consistent with the original intent of this disclosure requirement, the ACCC recommends that as part of the gas pipeline regulation reform RIS, SCO consider changing the NGR to require pipeline operators to publish the inputs used to calculate standing prices, so shippers can properly assess the reasonableness of these prices and the underlying assumptions. The ACCC also recommends that the AER consider developing a guide that provides pipeline operators with greater guidance on what, at a minimum, the pricing methodology should include and sets out the reporting requirements if a pipeline operator amends the pricing methodology.

6.3.3. The WAPs published by pipeline operators may not be meeting their stated objective

Operators of non-exempt non-scheme pipelines are required to publish information on the volume weighted average prices paid by shippers for services in the last financial year, in accordance with the AER's Guideline.[233] As the GMRG noted in its final recommendations on the design of Part 23, the publication of this information is intended to enable shippers to quickly determine whether a pipeline operator's offer (including the standing price) is reasonable relative to what others are paying.[234]

The obligation to publish WAPs commenced in October 2018, at which time pipeline operators were required to report initial WAPs information for the period 1 January 2018 to 30 June 2018. Box 6.1 provides further detail on the reporting obligations associated with WAPs.

232 GMRG, *Gas Pipeline Information Disclosure and Arbitration Framework: Final Design Recommendation*, June 2017, p. 58.
233 NGR, r. 556.
234 GMRG, *Gas Pipeline Information Disclosure and Arbitration Framework: Final Design Recommendation*, June 2017, p. 28.

Box 6.1: WAPs reporting requirement

The AER's Guideline requires pipeline operators to publish WAPs for the following services:

- transportation services
  - firm forward haul transportation services (includes bi-directional services, if a pipeline operates in a bi-directional manner)
  - interruptible or as available transportation service
  - backhaul services
- stand-alone firm compression services, and
- firm storage (i.e. park and/or park and loan services).

Where more than one charging method applies to a particular service, pipeline operators must also report the WAPs by charging method. For example, if a pipeline charges:

- some shippers on a distance235 or zonal236 basis and others on a postage stamp237 basis, then separate WAPs must be published for each charging structure
- some shippers a fixed charge and others a fixed and variable charge, then separate WAPs must be published for the fixed charge and the variable charge.

Pipeline operators can seek an exemption from publishing the WAP for a particular service if the service was provided, directly or indirectly, to no more than two users of the non-scheme pipeline. This exemption framework was introduced to address confidentiality concerns that were raised during the development of the framework.

In line with the Guideline, WAPs must be determined as follows:

Capacity based charges = $\frac{\$Revenue}{Maximum\ daily\ quantity}$

Volumetric based charging = $\frac{\$Revenue}{Gigajoules\ transported}$

The maximum daily quantity should to be measured in GJ, and revenue should be reported on an accrual basis.

While the requirement to publish WAPs has only recently commenced, questions have been raised by some users about the usefulness and quality of this information, and whether prices should instead be published on an individual basis.

This issue was considered by the GMRG when developing Part 23. While the GMRG could see the benefits of requiring individual prices to be reported, it was cognisant of the feedback stakeholders provided during the AEMC's 2015 East Coast Review in response to the following draft recommendation:[238]

> *"The Commission [AEMC] recommends that the actual (not advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price be published.*
>
> *…*

235 Where a charge for a service is based on the dollar per GJ per kilometre basis. Each major delivery point is required to be disclosed separately.

236 Where a pipeline is separated into zones and a separate tariff is calculated based on the number of zones through which gas is transported. Each zone is required to be disclosed separately.

237 Where the same charge is payable along the length of the pipeline, irrespective of the distance transported.

238 AEMC, *Stage 2 Draft Report: East Coast Wholesale Gas Market and Pipeline Frameworks Review*, 4 December 2015, pp. 71–72.

To the extent that pipeline owners are currently price discriminating, transparent historical prices, terms and conditions should place a discipline on pipeline owners not to undertake this practice. Even if price discrimination is not occurring in practice, transparency should give shippers confidence that this is indeed the case, and improve their negotiating power with the pipeline owners."

While some stakeholders supported this draft recommendation, a larger number expressed concerns about the proposed publication of this information. In most cases, the concerns centred on confidentiality. A number of stakeholders also noted that the benefits of publishing this information would be limited given the bespoke nature of the contracts.[239] The AEMC did not therefore proceed with this recommendation.

In the joint ACCC-GMRG transparency paper we noted that there would be value in revisiting this issue given the varying views previously expressed by stakeholders about the adequacy of WAPs. We therefore committed to examining the adequacy of the WAPs published by non-scheme pipelines and advising the Energy Council on whether this information should be retained, or if individual prices (or another alternative) should be reported in early 2019.

In keeping with this commitment, the ACCC has reviewed the WAPs published by pipeline operators in October 2018 to determine whether they are meeting their stated objective. To inform this review, the ACCC sought information and documents on how pipeline operators had derived the published WAPs, including intermediary calculations and individual shipper information. This information was used to test the veracity of the reported WAPs, and to see how they compared with pipeline operators' standing prices and the prices paid by individual shippers. The results of this review are set out below.

WAPs are not always comparable to standing prices

In developing Part 23, the GMRG noted that: [240]

"…the method used to calculate the weighted average price should result in a price that is directly comparable to the standing offer."

However, through our review we have found that WAPs and standing prices do not always reflect the same charges, and there are inconsistencies in how the information is reported.

For example, one pipeline operator has included additional charges and surcharges in their WAP calculations that are not included in their standing prices (i.e. because these charges are specific to individual shipper requirements and are not assumed under the general standing terms).

Some pipeline operators have also published WAPs for which there are no comparable standing prices. For example, where a service is charged on a volumetric-basis but the standing price is capacity based, or where services are no longer available. While this can be attributed to the scope of the reporting requirements, it is not particularly meaningful for shippers who want to compare prices.

The comparison of WAPs to standing prices can also be complex when different charging methods are used in individual contracts. For example, one shipper may be required to pay a fixed charge and a volumetric charge for a firm forward haul service, while another shipper may be required to pay a purely fixed charge. In this example, the pipeline operator would be required to report a WAP for both the fixed charge and the volumetric charge. This can make it difficult for shippers to compare the WAPs with the standing prices.

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[239] AEMC, *Submissions—East Coast Wholesale Gas Market and Pipeline Frameworks Review*, 28 July 2016.

[240] GMRG, *Final Design Recommendations: Gas Pipeline Information Disclosure and Arbitration Framework*, June 2017, p. 64.

WAPs are not representative of the prices paid by individual shippers

Table 6.2 compares the WAPs published by non-scheme pipeline operators for firm forward haul services with the prices paid by individual shippers over the same period (1 January 2018 to 30 June 2018).

Table 6.2: Comparison of published WAPs with prices paid by individual shippers for firm forward haul services between 1 January 2018 and 30 June 2018

Operator	Pipeline	Service	Published WAP ($/GJ of MDQ)	Range of prices paid by individual shippers ($/GJ of MDQ)	Difference b/w published WAP and individual shipper price range
APA	MSP	Zone 1 (Moomba to Wilton/Culcairn)	0.8034	0.7180–1.0525	-11% and 31%
	MSP	Zone 2 (Culcairn to Culcairn)	0.0698	0.0698–0.0702	-0.9% and 0.49%
	SWQP	Zone 1 Capacity based (Wallumbilla & Moomba)	0.9427	0.7060–1.2087	-25% and 28%
Epic	MAPS	Postage Stamp (Capacity based)	0.7908	0.7232 – 0.9903	-9% and 25%
	MAPS	Postage Stamp (Volumetric based)	0.6266	0.6279–0.7171	0% and 14%
Jemena	EGP	Zone 1 to Zone 1 (Capacity based)	0.5500	0.4414–0.6962	-20% and 27%
	EGP	Zone 1 to Zone 2 (Capacity based)	0.9707	0.9624–1.0717	-1% and 10%
	EGP	Zone 1 to Zone 3 (Capacity based)	1.1568	0.9475–2891	-18% and 11%
	QGP	Postage Stamp (Capacity based)	0.8626	0.7943–1.2912	-8% and 50%
SEA Gas	PCA	Postage Stamp (Capacity based)	0.6249	0.6074–0.6247	-3% and 0%
TGP		Zone 2 (Capacity based)	1.9326	1.4627–3.1897	-24% and 65%

Note: The WAPs must be reported by pipeline operators in accordance with the AER's Guideline. They may differ therefore from individual shipper prices, which are based on the prices specified in contracts.

As table 6.2 shows, with the exception of the PCA pipeline, the range of prices paid by individual shippers on the pipelines listed in this table deviates significantly from the corresponding published WAPs. For example, on the TGP one shipper is paying 65 per cent more than the published WAP, while another shipper is paying 24 per cent less than the published WAP for the same service. While this may, in part, be due to differences in contract terms and conditions and the time at which prices were agreed, it is clear from this comparison that published WAPs do not provide a good representation of the prices individual shippers are paying and could therefore mislead prospective shippers.

A number of other issues exist with WAPs

The ACCC's review of pipeline operators' WAPs also revealed:

- errors in a number of pipeline operators' published WAPs (for example, one pipeline operator included revenue for a service in the wrong service category)
- that the calculation of WAPs may be open to manipulation by pipeline operators (for example, the WAPs may be overstated through the inclusion of penalties (or as otherwise described), such as overrun and imbalance charges), and
- the exemption framework applying to WAPs (where exemptions are available if there are less than two users of the service) is limiting the availability of pricing information on some pipelines and for some key services.[241]

The ACCC has also found a number of deficiencies in the basis of preparation documents that pipeline operators are required to publish alongside the WAPs, which are set out in box 6.2.

Box 6.2: Review of pipeline operators' bases of preparation

The AER's Guideline requires pipeline operators to publish a basis of preparation that, amongst other things, sets out how the pipeline operator has calculated its WAPs, and, in particular:

- the source(s) relied upon
- the methodology employed, including any assumptions made, and
- where estimates have been used, the basis for the estimates, why actual information has not been used, and why the pipeline operator considers those to be best estimates and reasonable in the circumstances.

The ACCC has reviewed the basis of preparation documents published by the five major non-scheme pipeline operators to assess the quality of the WAPs information that has been reported. While in most cases the basis of preparation provides the source of the information and methodology used, the level of detail included varies significantly between pipeline operators. For example:

- While most pipeline operators used actual revenue and usage data based on invoices as inputs to their calculations, the source of the information used by some is unclear.
- The majority of pipeline operators (Jemena, APA and Epic Energy) have explicitly listed the charges that have and have not been included in their calculations for each service reported. However, other pipeline operators (SEA Gas and TGP) have provided less detail.
- Some pipeline operators (SEA Gas and TGP) have not included information on whether other charges such as imbalance, overrun and minimum monthly charges apply and how (if applicable) these charges have been dealt with. While APA includes information on how it has approached imbalance and overrun charges, it is silent on minimum monthly charges.

It is unclear therefore from some pipeline operators' bases of preparation how the WAPs

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241 In the six months from 1 January 2018 to 30 June 2018, exempt services accounted for all the revenue on the DDP and SESA, and majority of the total revenue on the PCI and BWP: see Jemena, *Darling Downs Pipeline*, 28 June 2019, https://jemena.com.au/pipelines/darling-downs-pipeline; APA, *South East South Australia pipeline,* https://www.apa.com.au/our-services/gas-transmission/central-region-pipelines/south-east-south-australia-pipeline/; SEA Gas, *Reporting template,* https://seagas.com.au/services/reports/financial-information/2018-pci-non-scheme-pipeline-financial-reporting-template/; APA, *Berwyndale Wallumbilla pipeline,* https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/berwyndale-wallumbilla-pipeline/, table 5.1.

have actually been calculated and, in particular, what charges have been included in the calculation. This is a significant deficiency in the reporting framework that further limits the reliance shippers can place on the WAPs reported by pipeline operators.

Improvements are required to ensure users have access to reliable information on the prices paid by other shippers

Together, the findings outlined above suggest that WAPs are not meeting their stated objective (i.e. to enable shippers to readily assess whether a pipeline operators' offer is reasonable relative to what others are paying). The ACCC has therefore given further thought to the improvements that could be made to ensure that prospective shippers have access to reliable information on the prices actually paid by other shippers for services when assessing the reasonableness of a pipeline operator's offer.

The two alternatives that the ACCC has identified, which were provided to SCO on 31 May 2019 are:[242]

1. reporting the individual prices paid by each shipper for services (plus key terms and conditions) instead of the WAPs,[243] or
2. reporting the minimum and maximum prices that shippers have paid for each service, in addition to the WAP for these services.

While the first alternative would provide prospective shippers with a better basis on which to assess the reasonableness of a pipeline operator's offer, the ACCC understands concerns have previously been raised by stakeholders about the effect that the publication of this information may have on competition in other markets, as well as around confidentiality. Some stakeholders, on the other hand, have noted that the lack of transparency around individual prices may enable pipeline operators to engage in price discrimination.

The competition concerns are less of an issue under the second alternative, which while not providing full transparency of prices, would still enable prospective shippers to:

- identify the outliers that are influencing published WAPs
- identify where published WAPs sit within the range of prices paid by shippers, and
- understand the extent to which price discrimination may be occurring.

It has not been possible for the ACCC to test these alternatives with shippers. The ACCC has therefore recommended that as part of the gas pipeline regulation reform RIS process, SCO consult on the two alternatives and consider what, if any, effect the disclosure of additional information might have on competition in other upstream and downstream markets. In doing so, SCO should also consider whether the exemptions that pipeline operators are currently able to obtain from reporting WAPs (i.e. if there are less than two shippers using the service) should be retained.

In addition to the recommendations to SCO, the ACCC also recommends that the AER consider:

- amending its Guideline and reporting template to address some of the deficiencies that have been identified through this review (for example, the lack of alignment between WAPs and standing prices and the complexities associated with different charging methods) and to improve the accessibility of the information, and

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242 ACCC, *Adequacy of weighted average pricing information: ACCC recommendations*, May 2019.

243 As noted in the ACCC-GMRG joint recommendations on measures to improve the transparency of the gas market, the risk of coordinated conduct amongst pipelines is relatively low because they are typically monopoly infrastructure. The publication of individual prices in this context is therefore less of a concern than it is for gas prices. ACCC and GRMG, Measures to improve gas market transparency, December 2018, pp. 13 and 34.

- providing further guidance to pipeline operators on the objective of the basis of preparation and the standard that is expected in these documents.

Further detail on these recommendations can be found in section 6.7.

6.3.4. The RCVs published for a number of pipelines have been overstated

Operators of non-exempt non-scheme pipelines are required to publish a range of financial information (including a statement of revenue and expenses, a statement of assets and the pipeline's RCV) on an annual basis. The rationale for requiring pipeline operators to publish this information is, as the GMRG noted, to enable:[244]

> *"…shippers to carry out a high-level assessment of the cost reflectivity of the standing offers. Even if the shipper does not use the information in this way, the publication of this information can be expected to impose greater discipline on pipeline operators when setting prices, because it will be clearer to market participants and policy makers if the pipeline is generating excessive returns."*

The financial information that pipeline operators are required to publish and the assurance requirements that must be complied with are set out in the AER's Guideline.[245] Amongst other things, the Guideline requires pipeline operators to publish the asset value arising from the application of the recovered capital method (RCM) (see box 6.3 for more detail). The publication of this value, which is reflected in the pricing principles that an arbitrator must have regard to under Part 23 of the NGR, is intended to provide an indication of the extent to which the costs incurred in constructing, augmenting and operating the pipeline have already been recovered from shippers.

Importantly, the pricing principles do not mandate the use of the RCM. Rather, they require the value of assets to be determined using an asset valuation method that is consistent with the objective of Part 23 and, unless otherwise inconsistent, to be calculated using the RCM. The RCM therefore acts as the starting point for the asset valuation in an arbitration, but it is open to the disputing parties to argue that an alternative method would be more consistent with the workably competitive market objective.[246] For example, if a pipeline was sold for a lower price than the RCV or if the RCV was higher than the cost of bypassing the pipeline, it would be open to a shipper to argue an alternative asset valuation method should be used.

The flexibility embodied in these principles was highlighted in the TGP arbitration, where the arbitrator decided to use a modified depreciated actual cost (DAC) method, rather than the RCM to value the assets.[247]

[244] GMRG, *Final Design Recommendation: Gas Pipeline Information Disclosure and Arbitration Framework*, June 2017, p. 45.

[245] Pipeline operators are required to publish this information using the AER's financial reporting template and must also set out the sources of any information relied upon and methodologies used in a basis of preparation.
As noted in r. 555 of the NGR, an arbitrator is not bound by the financial information published by pipeline operators, or by any of the methods, principles or inputs used to calculate the financial information.

[246] The ACCC understands that the pricing principles were structured in this way to try and simplify the arbitrator's task (i.e. by specifying the RCM as the starting point for the asset valuation), while also recognising that there may be circumstances where an alternative method would be more consistent with the outcomes of a workably competitive market.

[247] AER, *Final access determination—Tasmanian Gas Pipeline*, https://www.aer.gov.au/networks-pipelines/non-scheme-pipelines/arbitration-of-access-disputes/final-access-determination-tasmanian-gas-pipeline.

Box 6.3: Recovered capital method

The RCM, as its name suggests, is an asset valuation technique that takes into account the capital invested in the construction and subsequent augmentation of an asset, and the extent to which this capital has been recovered from users. This method is described in r. 569(4)(b) as:

- the cost of construction of the pipeline and **pipeline assets** incurred before commissioning of the pipeline (including the cost of acquiring easements and other interests in land necessary for the establishment and operation of the pipeline)

plus:

- the amount of **capital expenditure** since the commissioning of the pipeline

less:

- the **return of capital** recovered since the commissioning of the pipeline, and
- the value of **pipeline assets** disposed of since the commissioning of the pipeline.

As noted in the AER's Guideline,[248] the term **return of capital** is used to refer to the amount of capital recovered from users since the pipeline was commissioned, which is calculated as the difference between:

- the revenue earned by the **pipeline operator in each year**, and
- the costs incurred by the pipeline operator **in each year**, which include:
- the **operating expenditure** incurred by the **pipeline operator**
- the return on capital required by the pipeline operator, which is calculated by multiplying the capital base in each year by the rate of return that is commensurate with the prevailing conditions in the market for funds and reflect the risks faced in providing services, and
- the net tax liabilities incurred by the pipeline operator.

If the revenue earned by a pipeline operator is:

- greater than the costs listed above, the return of capital will be positive, which implies that some of the invested capital has been recovered and results in the RCV falling, or
- less than the costs listed above, the return of capital will be negative, which implies that there has been an under-recovery of costs by the pipeline operator and results in the RCV increasing.

The RCVs reported in October 2018 were significantly higher than expected

The obligation to publish RCVs commenced in October 2018. Table 6.3 sets out the RCVs that were published by pipeline operators at that time. It also sets out the accounting-based depreciated book values[249] pipeline operators are required to report in accordance with the AER's Guideline.

Before examining this table, it is worth noting that the RCVs reported by pipeline operators do not need to be reviewed or approved by the AER prior to publication. The Guideline does, however, require the values to be subject to a *limited assurance review* by an independent auditor. The standard for such a review is not whether the information is true and fair. Rather, the auditor is required to document whether anything has come to its attention that

[248] AER, *Financial Reporting Guideline for Non-Scheme Pipelines*, December 2017, pp. 19–20.
[249] Where a pipeline has been sold, the Guideline allows the book value to be based on the acquisition cost.

causes it to believe that the historical information "is not prepared, or presented fairly, in all material respects, in accordance with the applicable criteria".[250,251]

Table 6.3: Recovered capital values and book values reported by non-exempt non-scheme pipelines (as at 30 June 2018)

Owner	Pipeline	Construction cost plus augmentation costs ($m)	RCV ($m)	% of years where positive return of capital generated	Book Value ($m)	Ratio of Recovered Capital Value to Book Value
		(a)	(b)	(c)	(d)	(e)=(b)/(d)
APA	SWQP	$1 693.87	$2 082.70	13%	$2 387.21	0.87
	MSP	$1 405.39*	$2 083.60*	0%	$1 137.58	1.83
	SESA	$23.81	$36.28	0%	$15.31	2.37
	WGP	$2 060.89	$1 436.73	75%	$5 451.57	0.26
	BWP	$88.43	$96.10	40%	$84.69	1.13
Epic	MAPS	$489.56*	$579.82*	44%	$371.39	1.56
Jemena	EGP	$763.17	$834.28	40%	$1 730.81	0.48
	QGP	$375.08	$1 018.12	0%	$461.67	2.21
	DDP	$222.85	$193.96	85%	$495.12	0.39
	Vic Hub	$8.65	$3.67	60%	$15.02	0.24
SEA Gas	PCA	$494.79	$406.38	80%	$397.03	1.02
	PCI	$19.00	$13.76	73%	$13.27	1.04
TGP		$480.11	$933.80	0%	$212.64	4.39

Source: Tabs 1.1 and 4.1 of the financial reporting templates published by APA, Jemena, SEA Gas, Epic and Palisade on 31 October 2018.

Notes: * Construction cost based on the depreciated optimised replacement cost (DORC) values determined when the MSP and MAPS were regulated rather than the original construction cost.

As noted in the December 2018 interim report, the RCVs published by some pipeline operators were much higher than what the ACCC had expected. They were also higher than what a number of industry analysts expected:

> *"The MSP asset base of A$2.1bn was much higher than our forecast…"*[252]
>
> *"On APA estimates, no capital recovered ever [on the MSP]; possible stranding if revenues cannot be increased".*[253]

[250] The ACCC understands that it was necessary to adopt this lower level of assurance because the RCM may require a number of estimates to be made where historical information is not available.

[251] While there is limited oversight of the RCVs published by service providers, it is worth noting that the AER does have a compliance monitoring role and could seek civil penalties if the information reported by service providers was found not to comply with the access information standard in the NGR, or other requirements in the Guideline.

[252] Credit Suisse, *APA Group (APA AU)—Arbitration financials establish ex-bid value*, 1 November 2018, p. 1.

[253] ibid, p. 4.

> *"…the asset bases [of the SWQP and MSP] have proven to be larger than expected…In the case of MSP it has never obtained an acceptable return…, despite foundation contracts ending. SEAGas has only recovered 17% of its asset despite foundation contracts nearing an end".*[254]

The RCVs that were particularly noteworthy were:

- The MSP, SESA, TGP and QGP RCVs, because as column (c) in table 6.3 highlights, they imply that these pipelines have never generated a positive return of capital.[255] The RCVs of these pipelines are therefore substantially higher than the costs incurred in the construction and augmentation of the pipelines. They are also much higher than the book values (specifically, the TGP RCV is 4 times higher than the book value, while the MSP, QGP and SESA RCVs are 1.8–2.4 times higher).
- The SWQP, BWP, EGP and MAPS RCVs, because while they have earned a positive return of capital in some years (see column (c) in table 6.3), this has not been sufficient to offset the negative return of capital that has purportedly occurred in other years. The RCVs of these pipelines are therefore higher than the costs incurred in the construction and augmentation of the pipelines.
- The PCA and PCI RCVs, because while these pipelines have been fully contracted since they were built in 2004, the PCA has purportedly only recovered 17.8 per cent of the costs incurred in its construction and augmentation, while the PCI has only recovered 28 per cent of the costs.

For pipelines, such as the SWQP, which has undergone a major augmentation in the last five years, and the TGP, which has been underutilised since it was built, these results may not be unexpected. The same cannot be said though about the other pipelines, given a large proportion of their capacity is contracted, investment in these pipelines is continuing to occur[256] and, in the case of the MSP and MAPS, the pipelines are 42 to 50 years old.

The financial position that these pipelines are purportedly in, is also at odds with information pipeline operators have previously provided to the ACCC, which indicated that investments are ordinarily fully underwritten by shippers through medium to long-term GTAs. As noted in the ACCC's 2015 Inquiry, pipeline operators have informed the ACCC that the development of pipelines and subsequent expansions are typically underwritten by shippers through medium to long-term GTAs, because of the constraints imposed by financiers. This was reflected in the following statements made by one operator during its hearing:

> *"…if you want good debt terms, you can't have a lot of uncontracted capacity, otherwise your risk profile will change."*

> *"…we don't speculatively build capacity. Our business model would suggest that's too risky…."*

APA made a similar observation about the tendency for pipeline developments to be wholly or substantially underwritten by shippers in its response to the 2015 Inquiry Issues Paper:[257]

> *"…foundation shippers have historically underwritten the development and expansion of most pipelines."*

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254 Macquarie, *APA Group (APA AU)—Part 23 pipeline data—states no over collection*, 31 October 2018.

255 Nor have they purportedly earned sufficient revenue to recover the return on capital their operators claim to require.

256 For example, APA reportedly spent $178 m over the last five years expanding the capacity of the MSP, while Jemena spent around $115 m expanding the capacity of the EGP in 2014 and 2015.
See APA, *31102018—MSP Annual Financial Reporting for January 2018 to June 2018.xls*, tab 4.1 and Jemena, *EGP Dec 18 Non-scheme pipeline financial reporting guideline financial template.xls*, tab 4.1.

257 APA, *Submission responding to the ACCC issues paper*, 2 July 2015, pp. 5 and 16.

> *"[in the contract carriage model] investment is wholly or substantially underwritten by shippers who require the services"*

Jemena similarly observed in a submission to the AEMC's East Coast Wholesale Gas Market and Pipeline Review:[258]

> *"…long-term (in some cases up to 20 year) contracts between pipelines and shippers play a fundamental role in the gas transmission market, underwriting sunk investments."*

The ACCC has seen further evidence of the tendency for pipeline developments to be largely or wholly underwritten by shippers in internal documents obtained from pipeline operators through the current Inquiry.

As the preceding points highlight, there were some real concerns surrounding the veracity of the RCVs reported by pipeline operators in October 2018. The ACCC decided therefore to undertake a more detailed review of pipeline operator RCVs.

A review of a sample of RCVs revealed that they had all been overstated

The ACCC has focused on a sample of pipelines for this review:

- APA's SWQP, MSP and SESA
- Jemena's EGP
- SEA Gas' PCA and PCI, and
- Epic Energy's MAPS.[259]

To inform this review, the ACCC sought the documents and models relied upon by these pipeline operators to calculate the RCVs for each pipeline. This information was used to test the veracity of the inputs used, and the modelling carried out, to calculate the RCVs.

The review revealed that:

(a) a range of input and calculation errors had been made by pipeline operators

(b) one pipeline operator had employed a number of methods and assumptions that had the effect of inflating the RCVs of its pipelines

(c) the rates of return assumed by some pipeline operators were higher than the rates used internally and were also higher than the rates assumed by other pipeline operators and those allowed in contemporaneous regulatory decisions, and

(d) pipeline operators employed a range of different approaches to calculate key inputs (such as the rate of return, net tax liabilities, shared costs and the initial cost of the pipeline, with two pipelines using a depreciated optimised replacement cost (DORC) rather than the construction cost as the starting point).

The ACCC also identified a number of other gaps and deficiencies in the reporting framework and assurance process that could affect the reliability of the reported RCVs and the confidence that users of this information can place on these values.

The net effect of the matters set out in (a)-(b) is that the RCVs were overstated by up to 45 per cent (with over half of the sample being overstated by more than 20 per cent). If the rate of return used in the calculation of the RCVs was based on the rates allowed in contemporaneous gas transmission regulatory decisions, then the level of overstatement

[258] Jemena, *Pipeline Regulation and Capacity Trading Discussion Paper*, 20 October 2015, p. 7

[259] The ACCC emphasises that this is a sample only, and only covers eastern Australia. There are a number of other non-exempt non-scheme pipelines in WA.

would rise to up to 54 per cent. While the ACCC has not modelled the impact of the issues referred to in (d), they can be expected to have resulted in the values being further overstated.

The level of overstatement of RCVs is significant and suggests some pipeline operators are not taking the information disclosure obligations under Part 23 seriously, and are still exploiting information asymmetries to the detriment of shippers. The decision by some pipeline operators to behave in a manner that undermines the efficacy and intent of Part 23, does not reflect well on the rest of the pipeline industry, particularly given they advocated the adoption of this lighter handed approach over changes to the pipeline coverage test. The decision by some pipeline operators to behave in this manner is also at odds with the Energy Charter, which the ACCC understands a number of pipeline operators have signed up to.[260]

While the ACCC understands that only two pipeline operators[261] are currently using the RCVs to calculate standing prices (see Table 6.1), the values that have been reported by other pipelines could still result in shippers paying more than they should, because they are likely to have a bearing on a shipper's assessment of their prospects of success in an arbitration.[262] As noted in the discussion that follows, the ACCC is recommending a range of measures to address the issues identified. These measures may, however, take some time to implement. Shippers should therefore exercise some scepticism and caution in relation to the RCVs in the intervening period.

6.3.5. The RCVs include a number of calculation and input errors

In the course of our review, the ACCC identified a number of calculation and input errors, as well as internal inconsistencies that had been made by pipeline operators. The ACCC, for example, found cases where:[263]

- the revenue was understated because some categories of revenue were not included in the pipeline operator's RCV calculations
- the return on capital was overstated because:
    - a pre-tax return on equity was erroneously used in a pipeline operator's model to calculate the nominal vanilla weighted average cost of capital (WACC)
    - the pipeline operator has overstated the debt risk premium
    - the pipeline operator assumed a full year return on capital in a period that only covered six months
- the operating expenditure was:
    - overstated because the pipeline operator had inadvertently included depreciation and a number of categories of overheads that it should not have
    - understated because the pipeline operator did not include some expenditure categories in the RCV calculations
- the shared costs and assets were overstated because the pipeline operator had not allocated some of these costs and assets to another pipeline it owned, and

[260] The Energy Charter, *About the Energy Charter*, https://www.theenergycharter.com.au/about/.

[261] The pipeline operators are Epic Energy (*Moomba to Adelaide pipeline system: standing price information,* https://www.epicenergy.com.au/gmrg/Standing_Terms_Methodology.pdf) and SEA Gas (*Pricing methodology,* https://seagas.com.au/app/uploads/2019/02/Pricing-Methodology-20190204.pdf).

[262] While the ACCC understands that r. 555(2) clearly states that an arbitrator is not bound by the financial information published by pipeline operators, shippers may still consider their prospects of success against the value that is reported. Particularly if, for all intents and purposes, it looks like the values have been reported in accordance with the AER's guideline.

[263] The ACCC also found that Jemena had revised a number of the historic inputs used to calculate the EGP's RCV when it published its full year financial reports on 30 April 2019. For example, Jemena reduced the amount that was spent on pipeline additions between 2012 and 2017 by $5.88 million.

- the value of asset disposals was understated, because the pipeline operator did not include them in the RCV calculation.

The effect of these errors on the published RCVs varied across pipelines, with one pipeline's RCV being understated by 4 per cent while all the other RCVs were overstated by between 0.02 per cent and 45 per cent. When informed of the errors, a number of pipeline operators informed the ACCC that they did not consider the errors to be material and did not intend to publish revised estimates.

The effect of the errors was most pronounced on SEA Gas' PCA and PCI pipelines, with our analysis indicating that if the errors were corrected, the RCVs of these two pipelines would be 43 per cent to 45 per cent lower than what was reported. When notified of the errors, SEA Gas informed the ACCC that the modelling errors had been made by an external consultant responsible for conducting the RCV modelling. SEA Gas also advised the ACCC that it intended to use a different approach to calculate the return on equity, which would result in a marginally lower value for the PCA and PCI than what was published.

This decision is probably not surprising given the RCV is a key input to SEA Gas' standing prices (see table 6.1).[264] It is, however, disappointing that rather than acknowledging it has already recovered a significant portion of the cost of constructing and augmenting the PCA and PCI through its foundation contracts, SEA Gas has sought to maintain its original estimates by adopting an approach the ACCC has not seen used before to calculate the return on equity. SEA Gas' ability to do this highlights a more general concern the ACCC has with the discretion pipeline operators currently have when calculating the RCV and the lack of oversight of the values that are reported. To address this concern, the ACCC is recommending a number of changes to the process for reporting RCVs, which are set out in further detail below.

6.3.6. The methods and assumptions employed by one pipeline operator have had the effect of inflating its RCVs

Through its review of the RCV models provided by pipeline operators, the ACCC found that APA, which is an ASX listed company and champion of the Energy Charter, had employed a number of methods and assumptions, which had the effect of inflating the SWQP, MSP and SESA RCVs.[265]

APA had, for example, based its operating expenditure on an estimate of the "stand-alone" cost of operating each pipeline, rather than basing it on the actual costs incurred in operating each pipeline. APA has calculated the stand-alone costs of operating each pipeline by:

- applying a 10 per cent premium to the direct operating expenditure incurred in the operation of each pipeline between 2008 and 2018, and
- using an estimate of the corporate overheads that would have been incurred by each pipeline between 2016 and 2018 if they had their own board of directors, had their own IT systems and conducted their own corporate functions.

APA's use of the stand-alone approach is directly at odds with the Guideline, which requires the operating expenditure used in the calculation of the RCM to be based on *"the expenditure incurred by the service provider in each year following the construction".* [266] The Guideline also states that if the pipeline operator operates a covered pipeline (which APA does), the corporate overheads and shared assets should be allocated using the

[264] SEA Gas, *Pricing Methodology*, 4 February 2019, https://seagas.com.au/app/uploads/2019/02/Pricing-Methodology-20190204.pdf.

[265] While the ACCC has not reviewed the RCVs for other pipelines operated by APA, it is likely that the same methods and assumptions were used to calculate those RCVs.

[266] AER, *Financial Reporting Guideline for Non-Scheme Pipelines*, December 2017, p. 19.

methodology approved by the AER for the covered pipeline,[267] which APA does not appear to have done.

Apart from being inconsistent with the Guideline, the stand-alone approach is at odds with what all the other operators have done, which is to base their expenditure on actual costs incurred.

APA's use of the stand-alone approach was not limited to operating expenditure. Rather, it also employed this approach when:

- estimating the cost of debt used in the rate of return,[268] which included a 'single asset size premium' of 0.4 per cent to 2.8 per cent, and
- estimating the cost of shared assets, which were based on an estimate of the amount and proportion of corporate costs that would be incurred by a stand-alone operator.

The practical effect of this latter approach was that in 2018 approximately 90 per cent of APA's actual shared assets were attributed to the 12 non-exempt Part 23 pipelines that APA operates, even though it operates a large number of other pipelines, storage facilities and other infrastructure.

In addition to these inflationary measures, APA included related party margins and a related party contract close out payment (totalling around $128 m) in the calculation of the MSP's RCV between 2004 and 2012, even though the related party payments were disallowed by the ACCC when the pipeline was subject to regulation.[269]

Together these measures have resulted in the SWQP, MSP and SESA RCVs[270] being overstated by between 9 per cent and 25 per cent.[271] The level of overstatement is significant and highlights an apparent disregard for the objectives of the disclosure requirements and those shippers that may seek to rely on this information.

As noted above, a number of the measures appear inconsistent with the Guideline and potentially the access information standard, which states that information should not be false or misleading in a material particular.[272] The ACCC will therefore refer this matter to the AER.

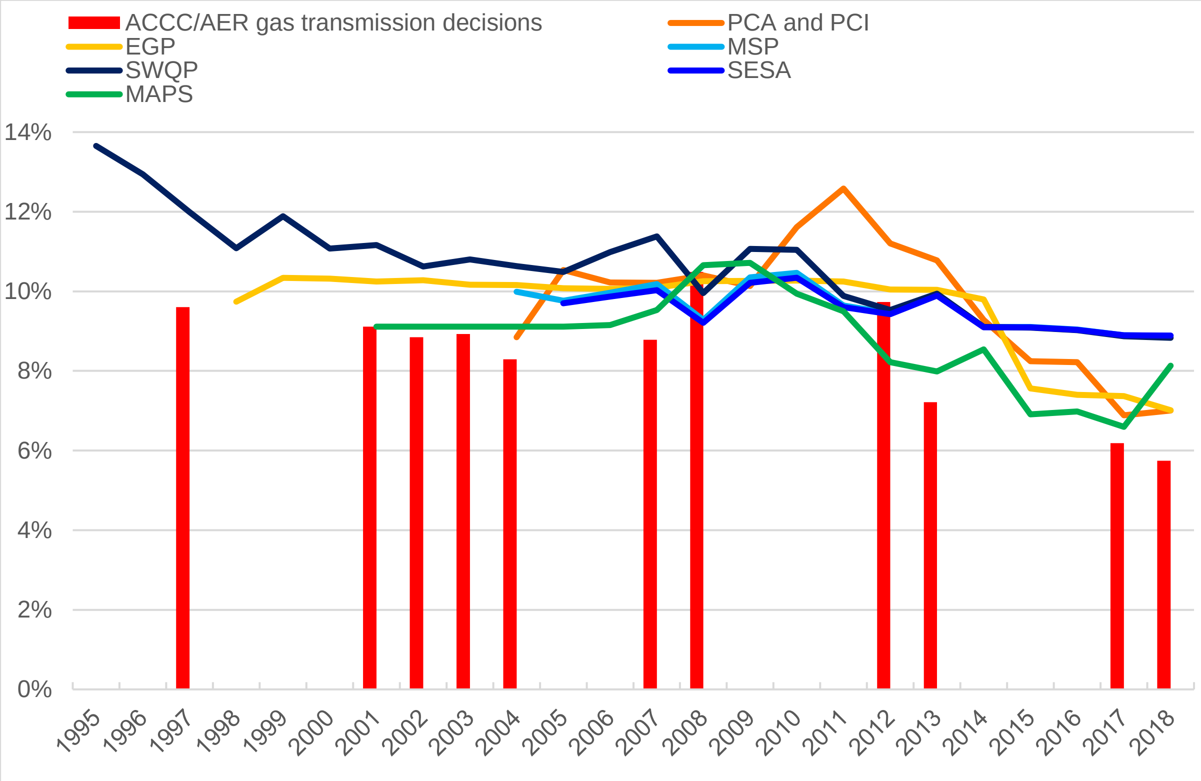
6.3.7. The rates of return assumed by most pipeline operators are too high

It is not possible from the information published by pipeline operators to determine what rates of return have been assumed in the calculation of the RCVs. The ACCC therefore sought this information from pipeline operators, along with information on the rates of return used by pipeline operators for internal purposes. This information revealed some instances where the rates of return used by pipeline operators to calculate the RCV were higher than those used for internal valuation purposes.

This information also revealed some marked differences between the rates of return assumed by each pipeline operator. The extent of this difference can be seen in chart 6.1, which shows the nominal vanilla WACC used to calculate each pipeline's RCV. This chart also shows the nominal vanilla WACC that was allowed in gas transmission regulatory decisions made by the ACCC up to 2008 and by the AER thereafter.

267 ibid, pp. 16 and 22.
268 APA, *Financial reporting guideline for non-scheme pipelines – Basis of preparation*, October 2018, p. 17.
269 ACCC, *Final Approval: East Australia Pipeline Limited Access Arrangement for the Moomba to Sydney Pipeline System*, pp. 39-40.
270 While the ACCC has not reviewed the RCVs for other pipelines operated by APA, it is likely that the same methods and assumptions were used to calculate those RCVs.
271 These values also reflect the correction of errors that the ACCC identified in APA's RCV model.
272 NGR, r. 551(2).

Chart 6.1: Nominal vanilla WACC assumptions



Sources: ACCC, Final Decision: Access Arrangement for the VTS (1 Dec 1997-31 Dec 2002), 6 October 1998, ACCC, Final Decision: Access arrangement for the MAPS (1 Jan 2001-31 Dec 2005), 12 September 2001, p. 53, ACCC, Final Decision: Access arrangement for the AGP (1 Jul 2001-30 Jun 2011), 4 December 2002, p. 96, GasNet Australia Access Arrangement Information (1 Feb 2003-31 Dec 2007), 23 December 2003, p. 6, ACCC, Final Approval: Access arrangement for the MSP (1 Jan 2004-30 Jun 2009), 8 December 2003, p. 36, ACCC, Final Decision: Access arrangement for the RBP (1 Jul 2006-30 Jun 2011), 20 December 2006, p. 120, ACCC, Final Approval: Access arrangement for the VTS (1 Jan 2008 – 31 Dec 2012), 25 June 2008, p. 7, AER, Final Decision: Access arrangement for the AGP (1 Aug 2011-30 Jun 2016), 20 July 2011, p. 80, AER, Final Decision: Access arrangement for the VTS (1 Jan 2013-31 Dec 2017), March 2013, Part 1, p. 25, AER, Final Decision: Access arrangement for the AGP (1 Jul 2016-30 Jun 2021), May 2016, p. 25, AER, Final Decision: Access arrangement for the VTS (1 Jan 2018-31 Dec 2018), November 2017, p. 26. Note that in those cases where the access arrangement period is based on a financial year, it appears in this chart as the next calendar year (for example, the RBP decision for the period 1 July 2006-30 June 2011 appears in 2007.

As this chart shows:

- The rates of return assumed by each pipeline operator vary markedly, with Epic Energy typically assuming the lowest rate for the MAPS, while SEA Gas and APA typically assumed the highest rate for their pipelines (for example, in 2011, SEA Gas assumed a return of 12.6 per cent for the PCA and PCI pipelines while Epic Energy assumed a return of 9.5 per cent for the MAPS).
- The rates of return assumed by pipeline operators are, on average, 0.3 per cent to 1.6 per cent higher than the rates allowed by the ACCC and AER in gas transmission regulatory decisions over the period. Interestingly, the rate of return assumed by Epic Energy for the MAPS is not materially different from that allowed by the ACCC/AER over the period, while the rates assumed by Jemena, APA and SEA Gas are all much higher.

While the differences between the rates of return assumed by each pipeline operator and between contemporaneous gas transmission regulatory decisions appear low in percentage terms, a small change in the rate of return can have a significant effect on the RCV. Some insight into the sensitivity of the RCVs to the rate of return can be found by replacing the rates of return assumed by each pipeline operator with the rates allowed by the ACCC/AER over this period. If this change was made and the errors and inflationary issues outlined above were also addressed, the RCVs for the sample of pipelines would fall by approximately 8 per cent to 54 per cent.

While some pipeline operators may claim that the rate of return should be higher than that allowed on regulated pipelines, it is worth noting that the risks faced by unregulated pipelines are no different to those faced by regulated gas transmission pipelines. This is because gas transmission pipelines tend to be regulated using a price cap form of regulation and are also subject to redundant capital risk. There is therefore no guarantee these pipelines will earn a specified level of revenue or return, as APA noted in its submission to the AER's rate of return guideline development process in 2013.[273] It would be open therefore to a shipper to argue in a negotiation or arbitration with a pipeline operator that the rate of return should be based on the rates allowed by the ACCC/AER over the relevant period, rather than the rates that have been assumed by pipeline operators.

6.3.8. Other inconsistencies in the calculation of RCVs are affecting reported values

In addition to the issues outlined above, the ACCC identified a number of inconsistencies in the approaches used by pipeline operators to calculate key inputs to the RCV calculation, all of which can have a material effect on the RCV. For example, the ACCC identified inconsistencies in the approaches used to:

- calculate the return on capital,[274] the rate of return[275] and net tax liabilities,[276] and
- allocate a parent company's shared costs and shared assets to a pipeline.[277]

These inconsistencies are not immediately apparent from the information reported by pipeline operators because the reporting template they are required to complete does not provide for any transparency of the calculations underpinning these inputs. The template does not, for example, require pipeline operators to show how the return on capital has been calculated or the rate of return that has been assumed in each year. Nor does it require pipeline operators to show how net tax liabilities have been calculated. The ACCC is therefore recommending that the AER consider amending its Guideline and financial reporting template to require greater transparency of these calculations.

In relation to cost allocation, the ACCC is concerned that there is scope for pipeline operators that own more than one pipeline to over-allocate the parent company's costs, or shift costs between assets over time to maximise the RCV (or in the case of the general financial reporting, minimise the reported return on assets). This issue highlights a more

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273 In its submission to the AER's 2013 rate of return guideline consultation process, APA observed that:
"In gas transmission, tariffs are regulated using price caps ...A gas transmission service provider, regulated under a price cap, will be exposed to the full effects of the reduction of revenue associated with the loss of a major customer. Under the price cap, the service provider cannot increase its tariffs during the current regulatory period to compensate for the loss in revenue from the failed customer. Furthermore, the NGR allow, in subsequent regulatory periods, removal from the regulatory asset base of the assets (now redundant) used to provide service to the failed customer. The service provider may not subsequently receive all or part of the return on the value of those assets, and all or part of the return of, the value of the assets."
See APA, Submissions responding to AER Draft Rate of Return Guideline, 11 October 2013, p. 12.

274 Some pipeline operators have, for example, calculated the return on capital by applying the rate of return to the opening value of the assets, while others have made provision for a half year return on capital expenditure incurred during the year.

275 Some pipeline operators have, for example, assumed a benchmark approach to calculating the cost of debt, while others have used the actual cost of debt, or an estimate of the cost of debt that would be incurred by a stand-alone entity. Some pipeline operators have also assumed benchmark gearing level of 60 per cent, while others adopted lower gearing levels.

276 Some pipeline operators have, for example, made provision for the value of imputation credits, while others have not.

277 Some pipeline operators have, for example, allocated the parent company's total shared costs and shared assets between all the assets they own, while others appear to have over allocated the parent company's shared costs and shared assets.

general concern that the ACCC has with different financial reporting regimes currently applied to full, light and Part 23 pipelines — because it is not possible to trace how the costs have been allocated across all of the parent company's pipelines. This is why the ACCC has in the past recommended the extension of financial reporting to full regulation pipelines, which would provide greater visibility of the allocation of costs between pipelines. This review has reinforced the need for this to occur. It also highlights the need for greater prescription to be included in the Guideline on how shared costs and assets are to be allocated.

Another issue that the ACCC identified when reviewing the MSP and MAPS RCV models is that Epic Energy and APA have used the DORC values that were established when the two pipelines were regulated as the starting point for their respective RCV calculations, rather than the original construction costs.

While the drafting in the current Guideline appears to allow this, the ACCC understands from the AER's Explanatory Statement, that its intention was to only allow a prior regulatory determination on the depreciated actual cost (DAC) of the pipeline to be used as the starting point and not a DORC value.[278]

The use of a DAC value as the starting point for the RCV calculation is understandable, because, like RCM, the DAC is based on historical costs.[279] DORC,[280] on the other hand, is a forward-looking replacement cost method, which is a fundamentally different construct to the RCM and could result in the RCV being overstated. Given this potential, the ACCC recommends that the AER consider amending its Guideline to bring it into line with its Explanatory Statement by only allowing a prior regulatory determination on the pipeline's DAC to be used as the starting point for the RCV calculations.

6.3.9. Other gaps and deficiencies in the reporting framework and assurance process are limiting the reliance that can be placed on RCVs

Through the review of RCVs, the ACCC has identified a number of instances where pipeline operators may have failed to comply with their obligations under the Guideline, including in relation to the information reported in their bases of preparation.[281] The ACCC will refer these compliance issues to the AER.[282]

The ACCC has also identified some significant deficiencies in the limited assurance reviews that were carried out by a number of auditors for pipeline operators. While the objective of the assurance process is to impose some discipline on pipeline operators and provide users with some confidence in the reported information, it is clear from the errors and inflationary

278 ACCC, *Explanatory Statement: Financial Reporting Guideline for Non-Scheme Pipelines,* December 2017, p. 24.

279 Under the National Third Party Access Code for Natural Gas Pipeline Systems, the term 'DAC' is defined as the value that would result from taking the actual cost of the pipeline and subtracting the accumulated depreciation for those assets charged to users (or thought to have been charged to users) (s. 8.10(a)).

280 The DORC valuation technique is a forward looking measure that has been described as the maximum price that a hypothetical new entrant would be willing to pay for second-hand assets with a reduced service potential, given the alternative of developing a new asset which has a greater remaining service potential. The calculation of DORC involves a two-step process:
Step 1: Estimate the cost of replacing the existing asset with a new optimally configured asset and sized asset that is constructed using modern engineering equivalent materials (the optimised replacement cost (ORC)); and
Step 2: Account for the difference between the service potential and costs of operating the existing asset and the optimised asset by 'depreciating' the ORC (DORC) on either a straight line basis or a net present value basis.

281 A number of pipeline operators' basis of preparation do not, for example:

- explain the steps they have taken to locate information where estimates have been relied upon
- describe how the estimates they have relied upon have been arrived at
- demonstrate that the estimates they have relied upon are the best estimate possible in the circumstances.

Some pipeline operators also appear to have failed to comply with the requirement in the Guideline for shared assets and shared operating costs to be allocated using the allocation methodology approved by the AER for their regulated pipelines.

282 Where relevant, the ACCC will also liaise with the Economic Regulation Authority, which is responsible for the economic regulation of gas pipelines in Western Australia.

measures outlined above that it has not achieved this objective. It would also appear from two of the auditor reports, that the auditor only considered whether the information was reported in accordance with the pipeline operator's basis of preparation, rather than in accordance with the Guideline. This further diminishes the reliance that can be placed on the auditor's opinion. The ACCC recommends a range of changes to the reporting framework and assurance process to address these deficiencies, which are set out below.

In addition to these issues, the ACCC has identified a gap in the access information standard in Part 23 of the NGR[283] with pipeline operators currently only having to correct information (including the RCV) that they have published if it is 'false or misleading in a material particular'. This is in contrast to other areas of the NGR where market participants are required to correct errors as soon as practicable after they have been identified. To address this gap, the ACCC recommends that the access information standard in the NGR be amended to require pipeline operators to republish information as soon as practicable once it is no longer accurate.

Improvements should be made to the process for reporting RCVs

To address the deficiencies outlined above, the ACCC is recommending a range of improvements to the process for reporting RCVs, which are intended to impose a greater level of discipline on pipeline operators and their auditors and provide shippers with a greater level of confidence in the reliability of the reported information.

Our recommendations are set out in detail in section 6.7. In short we recommend:

- Greater regulatory oversight of the RCVs and other financial information reported by pipeline operators. We suggest this be considered by SCO as part of the gas pipeline regulation reform RIS. Rather than requiring the AER to approve the RCVs, we suggest that SCO consider amending the NGR to give the AER power to require an independent review of a pipeline operator's RCV (which could take the form of an audit or a review by a regulatory expert). We also suggest that pipeline operators be required to provide the AER with the source material underpinning their RCVs.
- The AER consider amending its Guideline and financial reporting template to strengthen the reporting framework and improve the quality of the information reported by pipeline operators. Our proposed amendments will:
    - provide for a greater level of transparency of key inputs to the RCV calculation
    - limit the discretion pipeline operators currently have when calculating RCVs
    - improve the standard of the financial information and the basis of preparation by requiring an officer of the company (for example, a chief financial officer) to sign off on the reported information
    - improve the accessibility of the reported information, and
    - address other gaps in the Guideline and template that have been identified through this review.
- The access information standard in Part 23 of the NGR be amended to require pipeline operators to republish the information if it is no longer accurate.

The ACCC also recommends that the AER consider reviewing the RCVs published by the six pipelines[284] that were not included in the sample to determine whether they have been affected by the same or similar errors, inflationary measures and non-compliance issues.

283 NGR, r. 551.
284 These pipelines include APA's BWP and WGP, Jemena's DDP, QGP and VicHub and Palisade's TGP.

Other asset valuation methods may be more relevant in some circumstances

As noted in the introduction to this section, Part 23 does not mandate the use of the RCM. It would be open therefore to shippers to argue (either in negotiations or in an arbitration) that an alternative method would be more consistent with the outcomes of a workably competitive market, particularly when the pipeline has changed hands at a lower price than implied by the RCV at the time of the sale.

Through this review, the ACCC has identified a number of instances where the pipeline has changed hands at a lower price than implied by the RCV at the time of the sale. The MAPS, for example, was reportedly sold to QIC for less than $400m in 2013,[285] but at the time of the sale the RCV was estimated by Epic Energy to be $528m.[286] The prices paid by APA for the SWQP in 2012 and the SESA in 2007 were also lower than the estimated RCVs at the time of the sale.

The lower prices paid for these assets, in effect, means that the values were written down through the sale process, with the prior owners bearing the cost of the write down. It would be open therefore to a shipper to argue that the value of these pipelines should be based on the sales price (or some other value) rather than the RCV. Specifically, a shipper could argue that given the value of the asset was effectively written down through the sale, the new pipeline operator should not receive a windfall gain from the use of the RCV when setting prices.

6.4. Part 23 appears to be having an influence on negotiations

As noted in section 6.2, Part 23 sets out the process that shippers are to follow if they decide to seek access and the obligation that pipeline operators have to respond to access requests. It also sets out a number of requirements for negotiations and provides for the exchange of information between the parties during negotiations. The objective of this element of Part 23 was described by the GMRG as follows:[287]

> *"...to facilitate timely and effective commercial negotiations and minimise the reliance on arbitration."*

285 Robins, B, *QIC on lookout for more gas acquisitions*, Sydney Morning Herald, 8 October 2015, https://www.smh.com.au/business/qic-on-lookout-for-more-gas-acquisitions-20151008-gk4f5i.html.

286 Epic Energy, *31102018—MAPS Annual Financial Reporting for January 2018 to June 2018,* 31 October 2018, tab 4.1.

287 GMRG, *Explanatory Note: Gas Pipeline Information Disclosure and Arbitration Framework*, 2 August 2017, p. 6.

To determine whether this element of Part 23 is meeting its objective, the ACCC has reviewed a range of pipeline operators' internal board documents and information on shippers' access requests and pipeline operators' offers over the period 21 May 2018 to 15 March 2019. In carrying out this review, the ACCC has focused on:

- the form that access requests are taking
- the time taken to negotiate and the matters considered in negotiations, and
- the extent to which the threat of arbitration is being employed by shippers.
- The findings of our review are set out below.

6.4.1. The treatment of shippers' requests as preliminary enquiries may be delaying or avoiding negotiation obligations

Based on our review of the access requests received from shippers, it would appear that shipper requests are often treated as 'preliminary enquiries', rather than formal access requests under Part 23. It is not clear if pipeline operators are encouraging shippers to make preliminary enquiries, or if shippers are choosing to seek access in this way. It is also unclear if shippers are aware of the consequences of their requests being treated in this manner. The treatment of shipper requests as preliminary enquiries can, in effect, enable pipeline operators to avoid some of the rules in Part 23 that set out how they are to respond to access requests (including the period of time in which they are required to respond) and to negotiate under Part 23. Additionally, if negotiations fail and a shipper wants to proceed to arbitration, then it must submit a formal access request and go through access offer and negotiations steps in Part 23 before it can trigger the arbitration mechanism.[288]

The term 'preliminary enquiry' is not defined in the NGR and the prevalence of preliminary enquiries does not appear to be a compliance issue. Rather, it may be a shortcoming in Part 23. One option to remedy this issue would be to define the term 'preliminary enquiry' in the NGR. The ACCC, however, is of the view that a better remedy would be to remove the distinction between preliminary enquiries and formal access requests in Part 23 so that the rules regarding offers, negotiations and access to the arbitration mechanism apply to all requests made by shippers. The ACCC therefore recommends that SCO consider removing this distinction between preliminary enquiries and formal access requests as part of the gas pipeline regulation reform RIS.

6.4.2. Negotiations could be more informed if improvements were made to the quality, accessibility and usability of information

It would appear from our review of shippers' access requests and pipeline operators' offers that negotiations are taking around 1-2 months. Contract variations and extensions generally take less than a month to negotiate, whereas new contracts take longer.

It would also appear that standing prices are often used as the starting point for negotiations by both pipeline operators and shippers. While there are some exceptions, most shippers have been able to negotiate discounts from the standing price. In some cases, these discounts have been obtained as a result of changes to non-price terms. For example, in one negotiation, a pipeline operator accepted a lower tariff in exchange for higher overrun and imbalance charges that are payable if the shipper exceeds its nominated quantity. Another shipper agreed to enter into a longer contract term to obtain a lower price.

Some shippers also appear to be using standing prices to compare prices between pipelines, and using this comparison in their negotiations. However, this strategy appears to have had limited success.

288 NGR, r. 563(a).

It is unclear from the access request and offer information, or the feedback received from users through our periodic user surveys, whether shippers are actively using the WAPs and financial information to negotiate better deals or are seeking additional cost information from pipeline operators. This may be because the requirement to publish WAPs and financial information only recently commenced and/or the issues outlined in section 6.3. It may also be because the information published by pipeline operators is not always easy to locate (for example, one pipeline operator publishes its standing prices in its user access guide). The information is also, in some cases, not as easy to use and understand as it could be.

The ACCC is therefore recommending a range of measures to improve the quality, accessibility and usability of the information pipeline operators are required to report. Further detail on these recommendations can be found in section 6.7.

6.4.3. The threat of arbitration is being used in negotiations, but the credibility of the threat may not be as strong for smaller shippers

Based on the pipeline operators' internal board documents that we have reviewed, it would appear that some shippers are using the threat of arbitration under Part 23 in their negotiations with pipeline operators. This was also borne out in our user surveys, with one user noting the following:

> *"We had discussions regarding access and we were unsure whether we would get access or at what price. We successfully negotiated a lower price for access using the threat of Part 23."*

Pipeline operators also appear to be considering potential arbitration outcomes when determining prices.

While the threat of arbitration is being called upon by some shippers, concerns have been raised by one user about the potential for the threat of arbitration to be viewed as less credible when it comes from smaller shippers and for smaller shippers to have to pay more for transportation.[289] The ACCC has seen some evidence of this in the access requests and offer information, with some smaller C&I gas users being unable to secure the same prices offered to larger C&I gas users.

This is a potential weakness in the framework. The ACCC therefore recommends that as part of the gas pipeline regulation reform RIS, further consideration be given to whether the threat of arbitration is credible for all shippers, or if there are ways the credibility of the threat could be improved for smaller shippers.

6.5. The arbitration mechanism appears to be working as intended

While the arbitration mechanism is a key element of Part 23, it was not, as noted by the GMRG in the following extract, intended to be triggered very often: [290]

> *"…it is intended that commercial negotiation will continue as the primary means by which access terms and conditions are determined and that the arbitration mechanism will rarely be triggered. That is, it is intended that greater transparency and the threat of arbitration will be sufficient to encourage the parties to reach a commercial agreement".*

289 This is because the costs to a smaller shipper of triggering an arbitration may outweigh the benefits to the shipper. This could occur because the shippers' demand may be relatively small and/or the shipper's use of gas may be a small input to the shipper's end-use requirements.

290 GMRG, Final Design Recommendation: Gas Pipeline *Information Disclosure and Arbitration Framework*, June 2017, p. 2.

Since the introduction of Part 23, pipeline operators and shippers have negotiated 28 new GTAs and 98 variations to GTAs on the Part 23 pipelines listed in section 5.3. Over the same period, there has been just one arbitration (see box 6.4 for more detail). It would appear therefore that the intent of the arbitration mechanism is being met.

It would also appear from the information that is publicly available on the TGP arbitration[291] that key aspects of the arbitration mechanism worked as they were intended to. The arbitration was, for example, completed within the timeframe allowed for under the NGR. The pricing principles also appear to have been flexible enough to enable the arbitrator to select the asset valuation technique that was most consistent with the objective of Part 23 (in this case, a modified DAC) and to determine a price that, so far as practical, reflected the outcomes of a workably competitive market.

While not required by the NGR, TGP has decided to base its standing prices on the arbitrated outcome. Other shippers on the TGP have therefore been able to benefit from AETV's decision to trigger the arbitration mechanism. As noted in box 6.4, the prices emerging from this arbitration were lower than the prices that shippers had previously been required to pay for firm forward haul services, which represents a significant reduction.

Box 6.4: Tasmanian Gas Pipeline arbitration

In late 2017 an access dispute between TGP and AETV Pty Ltd (a subsidiary of Hydro Tasmania) was referred to arbitration. The access dispute related to the following services on the TGP:

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

This arbitration was conducted under the Tasmanian 'fast track' arbitration mechanism in the transitional rules of the NGR, which expired on 1 August 2018.[292] The fast-track mechanism modified a number of important steps under the standard arbitration mechanism in Part 23. For example, the arbitrator was required to grant leave to the parties to enable them to submit and rely on information not previously exchanged between parties.[293] The arbitration did not therefore occur on the basis of information exchanged by parties prior to the arbitration commencing as would usually occur under Part 23. As a result, the parties may have incurred higher costs through the arbitration than would ordinarily be expected under Part 23.

Notwithstanding this limitation, the arbitration was still completed within 90 business days,[294] with the final access determination made on 12 April 2018. Following the final determination, AETV entered into a GTA with TGP. TGP subsequently published standing prices, which are based on the arbitrated outcome.[295]

In January 2019, the standing prices for firm forward haul services were:

- Zone 1 (Comalco, Ecka): $0.9085/GJ
- Zone 2 (Bridgewater (Hobart), Burnie, Carrick/Hadspen, Longford Tasmania, Port Latta, Spreyton, Ulverstone, Westbury, Wynyard): $1.9192/GJ.

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291 Above n. 226.
292 NGR, Schedule 4, Part 3.
293 NGR, Schedule 4, Part 3, r. 9(1).
294 As noted in section 6.2, Part 23 requires the arbitration to be completed within 50 business days, but this timeframe can be extended to 90 business days if the parties agree to the extension.
295 TGP, *Part 23 User Access Guide*, 18 May 2018, p. 12.

As noted in our December 2018 report, prior to the arbitration the prices paid by shippers for firm forward haul services on the TGP between Longford and Hobart ranged from $1.97/GJ to $4.59/GJ. The price that shippers are now paying to transport gas between Longford and Hobart is based on the standing price of $1.9192/GJ, which is 3 to 58 per cent lower than the prices paid prior to the arbitration.

6.6. Part 23 is not acting as a disincentive to investment

Some pipeline operators have previously expressed concerns about the potential for the introduction of Part 23 to impede pipeline investments.[296] However, as the following list of investments that have been announced since the decision was made to implement Part 23 highlights, there is evidence that under Part 23 investment is still occurring: [297]

- Jemena's acquisition of the Darling Downs Pipeline from Origin in 2017[298]
- the development agreement APA entered into with Santos in 2017 to develop the Western Slopes Pipeline as part of Santos' proposed Narrabri Gas Project[299]
- the binding agreement Jemena entered into with Galilee Energy in October 2017 to develop a pipeline to connect the Galilee Basin to the east coast market[300]
- the agreement Jemena entered into with Senex in June 2018 to build, own and operate the 60 km pipeline that will connect the Senex Atlas field with the DDP[301]
- the development agreement APA entered into with AGL in 2018 to develop the Crib Point to Pakenham Pipeline as part of AGL's proposed LNG import terminal[302]
- Jemena's announcement in 2018 that it is moving ahead with early preparations for a potential $3 - $4 billion expansion and extension of the NGP to transport up to 700TJ of gas each day if sufficient gas is developed in the Northern Territory[303]
- the memorandum of understanding that APA, Comet Ridge Galilee and Vintage Energy entered into in May 2019, which provides for APA to build, own and operate a new pipeline to transport gas from the Galilee Basin to Moranbah in the first phase, with the second phase to connect the pipeline to the remainder of the East Coast Gas Market[304]
- the agreement Jemena entered into with Senex in June 2019 to buy the Roma North natural gas processing facility and pipeline[305]

The ACCC also found no evidence in pipeline operators' internal documents to suggest that Part 23 is deterring investment, which it would expect to if this was occurring.[306] Rather, the

296 See for example GMRG, Final Design Recommendation: Gas Pipeline Information Disclosure and Arbitration Framework, June 2017, p. 35; GMRG, Gas Pipeline Information Disclosure and Arbitration Framework: Initial Nation Gas Rules—Explanatory note for stakeholder consultation, June 2017, p. 22.

297 While this list focuses on the East Coast Gas Market, the ACCC is aware of a number of other investments that have been proposed in Western Australia
See for example: APA's Yamarna Gas Pipeline and Power Station and Mount Morgan Gas Pipeline (APA, Financial results for half year ended 31 December 2017, 21 February, https://www.apa.com.au/globalassets/asx-releases/2018/4--2018-02-21-1h-fy18-results-presentation-full-pack-final.pdf, p. 5.

298 Jemena, Media release: Jemena acquires Darling Downs Pipeline Network, 19 May 2017.

299 APA, ASX release: APA's agreement to deliver potential new source of gas for East Coast markets, 31 January 2017.

300 Jemena, Media release: Jemena fast-tracks plans to connect Galilee Basin to the east-coast gas market, 17 October 2017.

301 Jemena, Media release: Jemena and Senex partner to fast-track new gas supply to market, 18 June 2018.

302 APA, ASX release: APA to develop Crib Point Pakenham Pipeline for AGL's LNG import facility, 12 June 2018.

303 Macdonald-Smith, A, Jemena's $800m NT pipeline opens market for northern gas, Australian Financial Review, 14 December 2018, https://www.afr.com/business/energy/gas/nt-pipeline-opens-market-for-northern-gas-20181213-h1927i.

304 APA, Media release: Galilee Basin a step closer to the east coast, media release, 30 May 2019.

305 Senex, ASX release: Senex and Jemena agree $50 million infrastructure deal, 17 June 2019.

306 To the extent that any investments are not proceeding, then the cause is more likely to stem from the shift towards shorter term GSAs and GTAs (see section 5.3.1), which is limiting the willingness of shippers to underwrite investments.

ACCC found information that suggests pipeline operators are investigating a range of other pipeline investments that would be captured by Part 23, in addition to those outlined above.

6.7. Proposed improvements to Part 23

Based on our review of documentation and information provided by pipeline operators, the ACCC is concerned pipeline operators have not demonstrated a commitment to facilitating the objective of Part 23. This was further demonstrated by the disappointing level of cooperation and timeliness of the provision of information by pipeline operators during the ACCC's review process. The ACCC is therefore recommending a range of improvements to Part 23 that are designed to:

- pose more of a constraint on the behaviour of pipeline operators, by, for example, providing for greater oversight and prescription of the information to be reported by pipeline operators and removing the discretion to treat access requests as preliminary enquiries, and
- empower shippers by, for example, improving the quality, reliability and accessibility of the information that is reported by pipeline operators and ensuring the threat of arbitration is credible for all shippers.

These recommendations are summarised in table 6.4, the final column of which sets out how each recommendation should be progressed. As this column shows, we have suggested that a number of recommendations be considered by SCO as part of the gas pipeline regulation reform RIS process. The remainder will require changes to the AER's Guideline. Given the nature of the issues that we have identified and the number of significant pipelines that are subject to the reporting requirements, we do not think that these changes can wait for the RIS process to be completed. We therefore recommend that the AER consider amending the Guideline prior to the commencement of reporting in 2020. This timing will ensure the issues do not persist for an undue length of time and that shippers can have greater confidence in the reported information and more informed negotiations.

In addition to these recommendations, the ACCC intends to refer the compliance-related matters that it has identified through this process to the AER.[307] The ACCC also intends to continue monitoring the quality of the information reported by non-scheme pipeline operators and the timeliness and outcomes of negotiations with shippers.

Finally, it is worth noting that while this review focused on Part 23, recent amendments to the NGR have resulted in operators of light regulation pipelines having to publish similar information to non-scheme pipelines (for example, the pricing methodology and WAPs). Our observations on these disclosure requirements and the improvements that could be made should therefore also be considered in relation to light regulation.

[307] Where relevant, the ACCC will also refer compliance matters to the Western Australian Economic Regulation Authority.

Table 6.4: Summary of recommendations

Area	Recommendations	How to progress recommendation
Standing prices and pricing methodologies	As part of the RIS, SCO should consider removing the exemption that single user pipelines and pipelines with annual average gas flows of <10 TJ/day currently have from the obligation to publish standing prices and the standard terms and conditions of access on their website.	Gas pipeline regulation reform RIS
	As part of the RIS, SCO should consider whether pipeline operators should be required to publish the inputs used to calculate standing prices.	Gas pipeline regulation reform RIS
	The AER should consider developing a non-binding guide that provides pipeline operators with greater guidance on what, at a minimum, the pricing methodology should include and sets out the reporting requirements if a pipeline operator amends the pricing methodology.	Development of a new AER guide
Weighted Average Prices Information	As part of the RIS, SCO should consult with stakeholders on the following alternatives to the current requirement for pipeline operators to publish WAPs: 1. Reporting the individual prices (plus key terms and conditions) paid by each shipper for services instead of the WAPs. 2. Reporting the minimum and maximum prices shippers paid for each service, in addition to the WAP for these services. When consulting on the first option, consideration should be given to any impacts that the publication may have on competition in other upstream or downstream markets.	Gas pipeline regulation reform RIS
	To improve the WAP information that is currently reported by pipeline operators, the AER should consider amending its Guideline to require: • WAPs to only include charges that are comparable to those reflected in the relevant standing price and therefore to exclude any penalty charges (however described) • WAP categories to align as closely as possible with standing prices (for example, by requiring volumetric and capacity charges to be reported as a single WAP if that is how the standing price is expressed) • pipeline operators to identify any amendments made to the reporting template since the information was last published, and explain the reason for the amendments within the template itself, as well as in the basis of	Changes to the AER's Guideline and reporting template

Area	Recommendations		How to progress recommendation
	preparation (amendments should be signed by a competent officer of the company) • an officer of the company to complete a statutory declaration to certify that the WAPs calculations are true and correct when the information is published and when any amendments are made to the WAP information. To improve the accessibility of this information, the AER should consider amending its reporting template to include a summary tab that provides a "quick glance" view of the WAPs and the standing price for the equivalent point in time.		
Recovered Capital Method Asset Valuation	Greater oversight of published values	As part of the RIS, SCO should consider requiring greater regulatory oversight of pipeline operators' financial information to impose more discipline on pipeline operators and their auditors. Specifically, SCO should consider amending the NGR to: • give the AER the power to require an independent review (this could take the form of an audit or a review by a regulatory expert) of a pipeline operator's financial information (including the RCV) reported under Part 23 (the costs of which would be borne by the pipeline operators) • require pipeline operators to provide the AER with the source material underpinning their RCVs.	Gas pipeline regulation reform RIS
		The AER should consider reviewing the RCVs published by the six pipelines that were not reviewed by the ACCC to determine whether they have been afflicted by the same errors, inflationary measures and non-compliance issues. The AER should also consider assessing whether other aspects of the financial reports published by pipeline operators comply with the Guideline.	AER review of financial reports

	Improvements to the Guideline	The AER should consider amending its Guideline and/or financial reporting template to:
		• require greater transparency by, for example requiring pipeline operators to publish:
		  ○ how the pipeline's return on capital has been calculated and the rate of return assumed in each year (including all the parameters underpinning the calculation of the rate of return)
		  ○ how net tax liabilities have been calculated
		  ○ the total shared operating expenditure and shared assets incurred by the pipeline
			Changes to the AER's Guideline and reporting template

Area	Recommendations	How to progress recommendation

	operator’s parent company and how these costs have been allocated across all the assets owned and/or operated by the parent company.
	• limit pipeline operators’ discretion by, for example:
	  ○ only allowing previously regulated pipeline operators to use the DAC estimated by the regulator
	  ○ specifying whether mid-year adjustments of capital expenditure are permissible
	  ○ specifying the method to be used to allocate the parent company’s shared operating expenditure, shared assets and any shared revenue to the pipeline[308]
	  ○ specifying how ‘other revenue’ derived from the operation of pipeline assets are to be treated.
	• address other gaps that have been identified by, for example requiring:
	  ○ pipeline operators to explain material changes in operating expenditure
	  ○ pipeline operators to report information on the actual volume of gas transported by the pipeline in each year and the amount of capacity contracted on a firm basis in the year, so that shippers can use this information to calculate effective prices.
	• improve the standard of the financial information that is reported by requiring an officer of the company to sign off on the contents of the reporting template and basis of preparation when the financial reports are published and when any amendments are made to the financial reports.
	To improve the accessibility of the information, the AER should also consider amending the reporting template to include a summary tab that includes a “quick glance” view of some of the key financial information, including the pipeline operators’ RCV.	

Basis of Preparation	To improve the standard of the bases of preparation, the AER should consider providing pipeline operators further guidance on the objective of the basis of preparation and the standard that is expected in these documents (including the information to be reported and examples of how pipeline operators are to demonstrate that any	Changes to the AER’s Guideline

308 For example by reference to the method approved by the regulator on a coverage pipeline (as is currently provided for under section 3 of the Guideline) or in another guideline published by the AER.

Area	Recommendations	How to progress recommendation
	estimates have been arrived at on a reasonable basis and represent the best estimate possible in the circumstances).	
Requirement to republish information	As part of the RIS, SCO should consider amending the access information standard in Part 23 of the NGR (r. 551) to require pipeline operators to republish any information they are required to report, including the financial reporting template and/or basis of preparation, if it is no longer accurate.[309]	Gas pipeline regulation reform RIS
	To improve useability and provide greater confidence in the information reported, the AER should consider amending the Guideline to require pipeline operators to identify and explain the basis of any amendments to previously published information in the template and the basis of preparation.	Changes to the AER's Guideline
Improving the accessibility of information	To improve the accessibility of information, the AER should consider developing a non-binding guide on how the information pipeline operators are required to disclose, should be reported. This non-binding guide could set out what the standing price methodology should include, and for example could require pipeline operators to: • include a more prominent link on their website to where the information can be found and require all the relevant information for each pipeline to be included on a single page • report their standing prices and WAPs on a single page • escalate their standing prices to the relevant period so that shippers can quickly see the prices payable in that period. When developing this guide, the AER could also consider requiring links to the information reported by pipelines to be published on the AER's website so that shippers can more readily find the information.	Development of a new AER guide
Access requests	As a part of the RIS, SCO should consider removing the distinction between preliminary enquiries and formal access requests in the NGR.	Gas pipeline regulation reform RIS
Arbitration	As a part of the RIS, SCO should consider whether the credibility of the threat of arbitration could be improved for smaller shippers.	Gas pipeline regulation reform RIS

309 This mirrors the requirement in Part 18 of the NGR for Bulletin Board reporting entities to update information if it is "no longer accurate".