AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Gas inquiry 2017-2020

Interim report

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

Contents

Acronyms

ACT	Australian Capital Territory
ACQ	annual contract quantity
ADGSM	Australian Domestic Gas Security Mechanism
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DES	delivered ex-ship
DWGM	Declared Wholesale Gas Market
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
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSG	Gas Supply Guarantee
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
JCC	Japanese Customs-Cleared Crude
JV	joint venture
LNG	liquefied natural gas
MCQ	minimum contract quantity
MDQ	maximum daily quantity
MFN	most favoured nation
MMBtu	Million British Thermal Units–see below, Units of Energy
MPH	Moomba Processing Hub
NEM	National Electricity Market
NGL	National Gas Law

NGO	National Gas Objective
NGR	National Gas Rules
NSW	New South Wales
NT	Northern Territory
SA	South Australia
STTM	Short-term trading market
WA	Western Australia
Organisations	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy, originally the Australian Gas Light Company
APA	APA Group
APLNG	Australia Pacific LNG Pty Ltd
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
BHP	BHP Billiton, formed from a merger of BHP (originally the Broken Hill Propriety Company) and Billiton
CNOOC	China National Offshore Oil Corporation
COAG	Council of Australian Governments
EIA	Energy Information Agency (US)
FERC	Federal Energy Regulatory Commission (US)
GBJV	Gippsland Basin Joint Venture
GLNG	Gladstone LNG
GMRG	Gas Market Reform Group
NOPTA	National Offshore Petroleum Titles Administrator
PWC	Power and Water Corporation
QCLNG	Queensland Curtis LNG Project
QGC	QGC Pty Limited, previously Queensland Gas Company
RLMS	Resource and Land Management Services
SEA	Shell Energy Australia
SEC	Securities and Exchange Commission (US)

SGH	Seven Group Holdings
SPE-PRMS	Society of Petroleum Engineers-Petroleum Resources Management System
Pipelines	
BWP	Berwyndale to Wallumbilla Pipeline
CGP	Carpentaria Gas Pipeline
CRP	Central Ranges Pipeline
CRWPL	Comet Ridge to Wallumbilla Pipeline Loop
CWP	Central West Pipeline
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
QSN Link	Queensland to South Australia/New South Wales Link
RBP	Roma to Brisbane Pipeline
SEAgas	South East Australia Gas pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline

Glossary

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

AEMO-operated wholesale markets: There are two broad kinds of AEMO-operated wholesale markets: demand hubs, and supply hubs. The Victorian Declared Wholesale Gas Market (DWGM) and the Adelaide, Sydney, and Brisbane Short Term Trading Markets (STTMs) can be considered demand hubs as their primary purpose is to meet the gas requirements of a particular demand centre. These markets are compulsory–if a user sits within the defined boundaries of the market, their gas use (or supply) will be scheduled through the market by AEMO. The Wallumbilla and Moomba Gas Supply Hubs were developed primarily to facilitate the trade of gas between suppliers and large users at a particular supply centre. These markets are voluntary.

Aggregator: an entity other than a gas retailer that purchases gas for the purpose of re-supply to end users (including C&I users and GPG) rather than for their own consumption.

Banking rights: A contractual term relating to a gas user's maximum gas usage allowance in a given period. When a gas user consumes less than their maximum, banking rights determine the extent to which the user may 'bank' the difference for later use.

Conventional/unconventional gas: Conventional gas is contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the three major types of unconventional gas as:

- shale gas: natural gas contained within shale rock
- coal seam gas (CSG): natural gas contained in coalbeds
- tight gas: natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require a large number of wells to be drilled (in the thousands for the large CSG liquefied natural gas (LNG) projects in Queensland) over its life to ensure consistent production.

Delivered ex-ship price: The price of gas delivered by ship to a destination port. This term is typically used for LNG prices.

Domestic demand: The quantity of gas demanded by users located in Australia.

East Coast Gas Market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

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

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

Liquefaction: The process of liquefying natural gas.

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

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

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

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

Pipeline transportation services

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

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

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

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

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

Reserves and resources

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

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

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

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

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

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

Transportation and storage related terms:

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

Gas storage service: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

Secondary capacity: Capacity that is on-sold by primary capacity holders on a pipeline.

Shipper: A user of pipeline services.

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

Southern States: South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Spot market/transaction: One-off transactions, as distinct from transactions occurring under supply contracts.

Swap arrangement: An arrangement between two or more gas market participants to swap rights or obligations. For example, two gas producers in different locations may swap gas delivery obligations to minimise transportation.

Take or pay: A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year.

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

Units of Energy

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

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

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

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

Million British Thermal Units (MMBtu)

Overview

This is the second interim report of the Australian Competition and Consumer Commission's (ACCC) inquiry ('the Inquiry') into gas supply arrangements in Australia. The ACCC is focussing on the operation of the East Coast Gas Market, where there are continuing immediate and longer-term concerns.[1]

In the September 2017 report, the ACCC reported on the supply-demand outlook for 2018. The ACCC found that there was likely to be a substantial gas supply shortfall in 2018 and that commercial and industrial (C&I) users were experiencing difficulties in obtaining gas supply for 2018. In the first part of 2017 in particular, C&I users had few suppliers offering them gas for supply in 2018. Where gas was offered, it was generally at prices well above the ACCC's estimates of benchmark prices.[2] The ACCC also reported that there was insufficient participation during this period by the Queensland liquefied natural gas (LNG) producers in offering gas to the domestic market for supply in 2018, given that they were collectively forecasting significant LNG export spot sales for 2018.

On 3 October 2017, the Australian Government reached a Heads of Agreement with the LNG producers. In the Heads of Agreement, the Government acknowledged that the east coast LNG industry is a net supplier to the domestic market. However, to ensure the security of supply of gas to Australian users, the Government obtained an agreement from the LNG producers that they would offer sufficient gas to the domestic market to meet the expected supply shortfall in 2018 and 2019 and that those offers would be made on reasonable terms.

Information obtained by the ACCC since the September 2017 report shows that LNG producers have made significant additional quantities available to the domestic market over the past few months and there have been some improvements in the availability of gas and prices offered to gas users in the East Coast Gas Market. However, the East Coast Gas Market is still not functioning effectively and domestic prices are still in excess of the ACCC's estimates of benchmark prices.

From the longer-term perspective, the East Coast Gas Market is being transformed by significant changes to the gas supply and demand profile, the role and use of infrastructure, and domestic gas prices. These changes are altering the operation of the East Coast Gas Market and the transition has been, and likely will continue to be, difficult for many participants.

There have been some short-term improvements in market conditions, but the East Coast Gas Market is still not functioning effectively

There has been an improvement in the quantity of gas made available for supply in 2018

Over the past few months, the Queensland LNG producers have diverted significant quantities of gas into the domestic market. The LNG producers have contracted 42 petajoules (PJ) of gas under long-term gas supply agreements (GSAs) to domestic buyers for supply in 2018 since the September 2017 report. This was enabled by the LNG producers reducing their planned exports for 2018. Collectively, the LNG producers reduced their LNG export contract and LNG feed gas requirements for 2018 by 34 PJ and their

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1 The East Coast Gas Market currently includes Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania. The Northern Territory will be connected to the East Coast Gas Market from 2019 and has been included in this report as part of the supply outlook from 2019. This report does not cover Western Australia for reasons set out in the September 2017 report.

2 The ACCC's estimates of benchmark prices (that is, prices that would be expected in a well-functioning market) are based on Asian LNG spot netback prices and production costs as set out in chapter 2.

planned LNG spot sales by 29 PJ. The LNG projects are still forecasting to sell 34 PJ on the international LNG spot markets in 2018.

The bulk of the gas sales by the LNG producers were to aggregators and retailers. While a substantial portion of this gas will be used to supply customers that were already contracted, the rest of the gas was used to enter into new GSAs with C&I users and gas powered generators (GPG). In total, aggregators and retailers have sold 32 PJ of gas for supply in 2018 since the September 2017 report.

As a result of additional supply being made available and a reduction in planned exports, there is now a lower likelihood of a supply shortfall in the East Coast Gas Market in 2018, as shown in table 1. However, the gas supply-demand balance in the market remains tight.

Table 1 – Supply-demand outlook in the East Coast Gas Market for 2018

	Expected domestic demand scenario (PJ)	Upper band domestic demand scenario (PJ)
Supply	1913	1913
Domestic demand	642	695
LNG demand	1251	1251
Projected balance	**20**	**(33)**

Notes: Total forecast supply includes forecast storage depletions expected to occur over 2018. Domestic demand estimates are based on AEMO data from its September 2017 Gas Statement of Opportunities. LNG demand includes volumes forecast to be required by the Queensland LNG projects to meet their long-term export commitments and their projected LNG spot sales. Except for AEMO's forecasts of domestic demand, the information provided in the table is based on data obtained by the ACCC directly from gas suppliers.

Transportation constraints are limiting the ability of market participants to deliver additional gas to where it is needed most

As reported in the September 2017 report, there will be insufficient production in the Southern States[3] in 2018 to meet forecast domestic demand. This means that gas users in the Southern States are relying on gas produced in Queensland to be transported into the Southern States to meet their needs. The gas shortfall in the Southern States can add at least $2/GJ and possibly up to $4/GJ to the prices paid by gas users in those states. In addition, access to pipeline capacity, particularly on the key north to south transport routes, is increasingly important to market participants.

At present, most of the key pipelines necessary to deliver gas from Queensland to the Southern States are close to fully contracted in 2018.[4] The two largest retailers have contracted a significant proportion of the firm transportation capacity on these key pipelines.

This means that, in the short term, other parties seeking to transport gas from Queensland into the Southern States who do not hold firm capacity on these pipelines could alternatively:

- negotiate with an existing capacity holder for secondary capacity

[3] South Australia, New South Wales, the Australian Capital Territory, Victoria, and Tasmania.

[4] They key north to south pipelines include South West Queensland Pipeline, Moomba to Adelaide Pipeline System and Moomba to Sydney Pipeline.

- acquire capacity from pipeline operators through as-available or interruptible services, or
- enter into gas swap arrangements.

The ACCC examined whether retailers who control the pipeline capacity on key pipelines to move gas south were making unused capacity available to other market participants. The ACCC generally did not find evidence to suggest retailers are purposely withholding capacity. The retailers that hold the firm capacity rights on the key north to south pipelines are generally using their capacity, although in non-peak periods throughout the year there is spare capacity which could be made available through secondary capacity trading.

However, the ACCC did receive some claims alleging that on some other pipelines, retailers' unwillingness to trade secondary pipeline capacity restricted competition for the supply of gas to C&I users connected to those pipelines. Following the ACCC's investigation into the conduct of those retailers, we have observed that those retailers are now making spare capacity available on those pipelines for use by other market participants. This has resulted in more competitive outcomes by giving gas users a greater choice for sourcing gas supply. The ACCC will continue to monitor the utilisation of pipeline capacity and whether retailers are making spare pipeline capacity available to the market on reasonable terms.

In the absence of firm capacity, there is demand for as-available or interruptible services on the key north to south pipelines. However, these services are lower in priority than firm services and the prices of interruptible services on some of the key north to south transport routes are set at a relatively high multiple of the firm transportation rate.

Some market participants have entered into gas swap arrangements to overcome pipeline congestion on the key north to south transport routes and are paying fees that are lower than transportation costs. While there are benefits in engaging in gas swaps, there are limits on how much gas can be swapped between locations.

Critically, pricing for pipeline services has remained high, with little change from the monopoly pricing identified in the ACCC's 2015 inquiry. However, the ACCC expects that prices should come down as a range of regulatory reforms in respect of access to firm and secondary pipeline capacity begin to take effect.

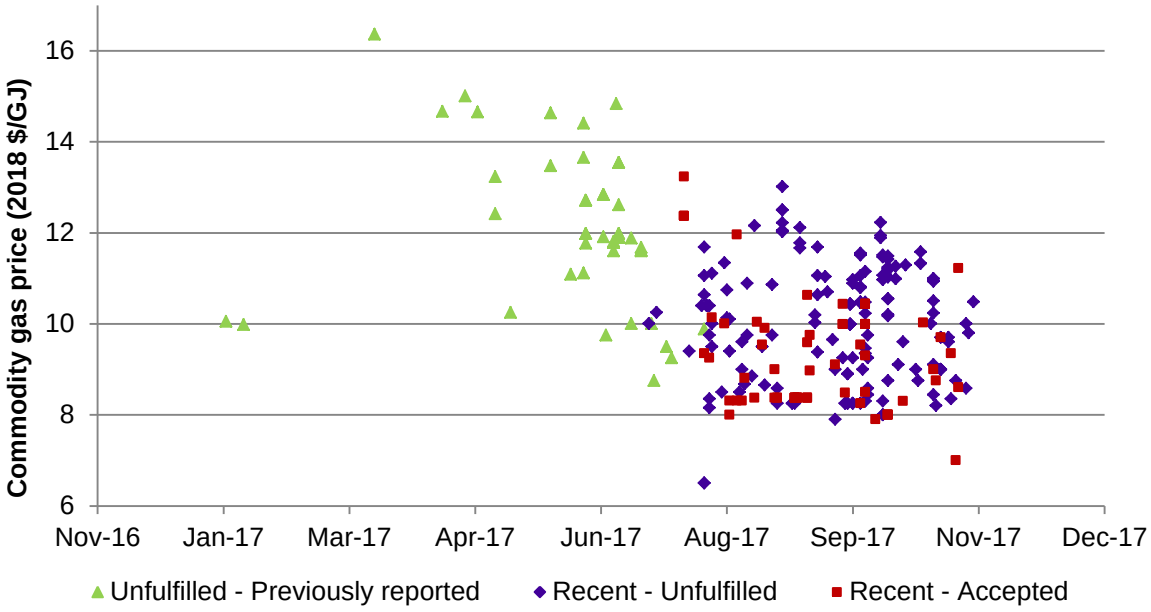
On the whole, limited access to reliable and reasonably priced transportation capacity on key pipelines appears to be constraining the ability of some market participants to bring gas from Queensland into the Southern States, which is limiting the level of competition for gas supply in the Southern States.

Prices offered to C&I users have fallen substantially since early 2017, but contracted prices remain higher than the ACCC's benchmark estimates

Gas prices offered to large C&I users that consume more than one petajoule of gas per annum reached a peak of $16/GJ in early 2017, while some prices offered to smaller C&I users by retailers were even higher. Given these high prices, many C&I users chose to delay contracting for 2018 supply at the time.

Since July 2017, commodity gas prices offered to large C&I users have eased and have generally been made at $8–12/GJ, as shown in chart 1.

Chart 1: Unfulfilled offers between 1 January 2017 and 14 July 2017 and all subsequent offers up to 9 November 2017 across the East Coast Gas Market



Source: ACCC analysis of offers provided by suppliers

Note: Offers up to 14 July are for annual quantities of at least 1 PJ; offers after this are for annual quantities of at least 0.5 PJ.

As offered prices declined, C&I users have become more willing to enter into GSAs, with around 12 large C&I users recently contracting with retailers or aggregators for 2018 supply.

While 2018 prices under recently agreed GSAs are considerably lower than prices that were being offered in early 2017, prices that are expected to be paid in 2018 under the recently struck GSAs are similar to, or higher than, those prices that were agreed for 2018 supply under GSAs entered into in 2016.[5] Further, the recently agreed 2018 prices remain largely at the upper end of, or above, the prices that would be likely to prevail in a well-functioning and competitive market.

In Queensland, wholesale gas prices set by LNG producers for 2018 supply between June and November 2017 have averaged $8.38/GJ. This is higher than the forecast average spot LNG netback price at Wallumbilla for 2018, which ranged between $5.87/GJ and $7.85/GJ over this period.[6]

In the Southern States, wholesale gas prices set by producers between June and November 2017 have averaged $9.74/GJ. This is at the upper end of, or higher than, the ACCC's estimates of benchmark prices in the Southern States, which range between $6.55/GJ and $9.93/GJ.[7] The benchmark estimates vary depending on a gas user's location, with the upper limit of the range relevant for users in Victoria and the lower limit for users in South Australia.

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5 Producer prices reported in the September 2017 report were largely based on GSAs executed in 2016. For the purpose of comparing the producer prices struck under recent GSAs, the prices reported in the September 2017 report need to be adjusted to reflect the same economic parameters as were used in this report (i.e. oil prices, exchange rates and CPI).

6 The lower end of this range reflects the ACCC's estimates of the forecast average spot LNG netback price for 2018 based on expectations about Asian LNG spot prices at the time of the September 2017 report, while the higher end of this range reflects the estimates based on expectations about Asian LNG spot prices for 2018 as at the end of November 2017.

7 The ACCC's estimates of benchmark prices in the Southern States are based on the forecast average spot LNG netback price for 2018 at Wallumbilla, adjusted for the transport differential between the relevant locations (as explained in chapter 2).

Commercial and industrial users say that despite recent improvements, the gas market remains extremely challenging

Following the publication of the September 2017 report, the ACCC sought updates from C&I users that were uncontracted during the previous round of consultation and contacted some smaller C&I users about their experiences in the market. On the whole, C&I users informed the ACCC that market conditions have improved since the September 2017 report. Some C&I users thought that the government's focus on the gas industry and the ACCC's market monitoring were likely contributors to these improvements. However, user experiences varied depending on size.

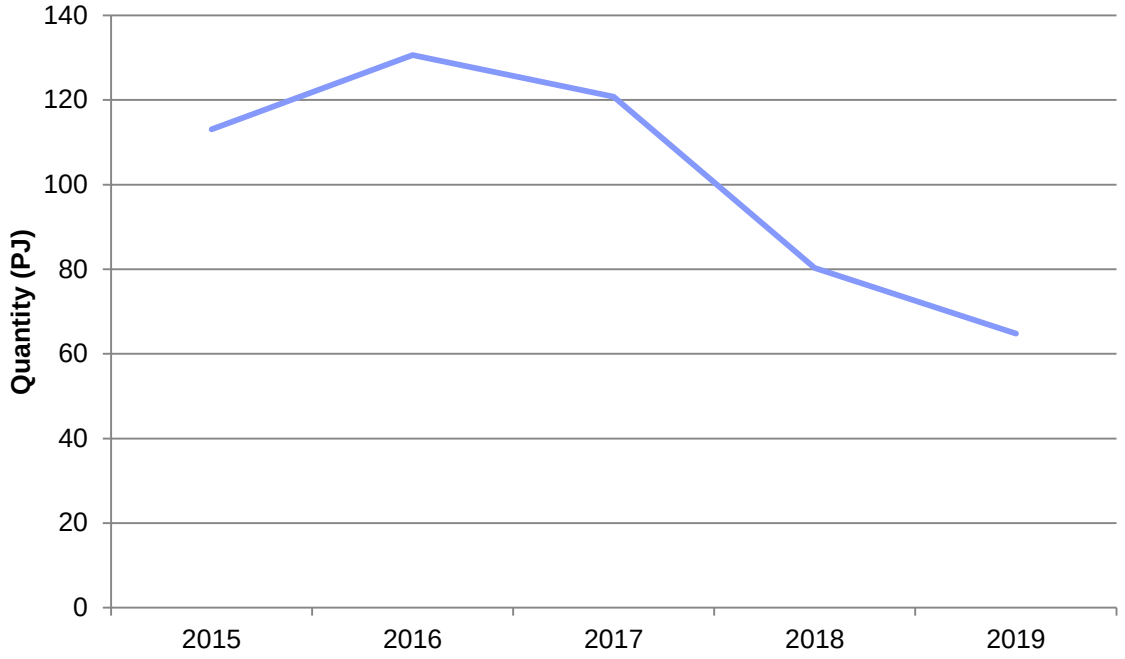
Over the past few months, large C&I users consuming over one petajoule of gas per annum have received substantially lower price offers than in early 2017 and have had more engagement from suppliers. Nearly all of the 10 large C&I users we recently spoke to have entered into GSAs for supply in 2018, with the one remaining uncontracted user in negotiations. These users generally had 2-3 competing suppliers making offers to them and two users had offers from six different suppliers.

The experience of C&I users that consume smaller quantities of gas has been somewhat different. These C&I users are typically not large enough to enter into negotiations directly with producers and have to rely on retailers for gas supply. They informed the ACCC that prices offered to them by retailers have come down from around $18-19/GJ in the first half of 2017 to about $11/GJ or less. However, in some cases they are still only receiving offers from one or two retailers, with some users reporting that retailers continue to claim to have no gas available.

Recent behaviour of some retailers towards C&I users who were seeking to re-contract is not what would be expected in a well-functioning market. In some instances, unwillingness by a retailer to offer gas to long-term customers whose contracts were expiring put these C&I users into a difficult position in respect of their ongoing operations into 2018, potentially creating significant effects in local economies and beyond.

Information received by the ACCC from the three major retailers shows a significant reduction in the quantity of gas that some of them have contracted for 2018 and 2019 compared to the previous years, as shown in chart 2.

Chart 2: Quantity of gas supplied, or contracted to be supplied as at 18 October 2017, by major retailers to C&I users



Source: ACCC data, as at 18 October 2017

It appears that due to limited gas supply and higher gas prices, some retailers consider that they now face higher risks in supplying C&I users than they had in the past. In particular, some retailers are concerned that, given the current high gas prices, if they purchase large quantities of gas before signing up customers, they may not be able to sell the entire quantity of gas under long-term GSAs and would have to sell it at lower prices on the domestic spot markets instead. Some retailers are also concerned that, at current gas prices, C&I users are at higher risk of market exit, which could again put the retailer into the position of having to sell undelivered quantities of gas into the domestic spot markets.

While price offers received by both large and smaller C&I users are now lower than they were earlier in the year, many C&I users consider that current prices are unsustainable for their businesses over the long term. This has led to some choosing to hold off entering into GSAs for 2019 in the hope prices will improve further. This is an issue of great concern. A number of small C&I users have also joined together to form a larger buying group. This enables these users to negotiate directly with gas producers and aggregators, opening up greater opportunities for gas supply and resulting in improved offers.

Over the period May–July 2017, the Gippsland Basin Joint Venture used a blind tender process to sell gas in Victoria. All of the successful bidders were retailers and/or gas powered generators (GPGs). The results of this tender appear to indicate that if the East Coast Gas Market is short on gas and different types of buyers are required to compete for gas supply, C&I users may be crowded out by other gas users, particularly GPGs. In circumstances where GPGs are increasingly setting prices in electricity markets, they are more likely to be able to pass on higher gas prices to their customers than C&I gas users, a number of which produce trade exposed products.

The East Coast Gas Market is undergoing a challenging market transition

While the diversion of exports into the domestic market by the LNG producers has resulted in short-term market improvements, the longer-term issues in the East Coast Gas Market remain.

The East Coast Gas Market is currently undergoing a significant transition, which has been accelerated by the simultaneous construction of the three LNG projects in Queensland and more recently by the changing role of gas powered generation in the electricity market. The speed of the transition has been difficult for many market participants, particularly C&I users, many of which have seen gas prices double or even triple in a relatively short period of time.

While increases in gas prices from historically low levels were always likely, the effects of the transition have been exacerbated by a combination of ongoing market uncertainty about the supply-demand outlook, lower investment levels in exploration and development (affected by reduced oil prices and government policies) and infrastructure constraints.

Supply and demand profiles are changing

Traditionally, gas users in the Southern States relied on local production from offshore Victoria and the Cooper Basin in South Australia. However, based on current estimates, production from these sources is insufficient to meet current domestic demand in the Southern States and there is currently little prospect of this changing in the medium to long term.

Most major known gas fields in these areas have already been developed and are nearing depletion. Market uncertainty and reduced oil prices, which are now around their long-run average levels, have limited investment in exploration and development in offshore Victoria and the Cooper Basin. Producers in offshore Victoria are increasingly reliant on smaller resources with higher levels of impurity, which are harder and more costly to produce. There are only a limited number of new offshore resources that have currently been identified for development, most of which are either highly uncertain or not expected to bring material quantities into the market.

As observed by the ACCC in the September 2017 report, the best way to address the supply shortage in the Southern States is to increase production of gas in the Southern States. This would reduce the reliance on gas from areas located far away and, depending on the cost of producing this gas, is likely to place the biggest downward pressure on gas prices in the Southern States.

There are a number of potential onshore gas resources that could help to address or mitigate the impacts of the shortage on gas users in the Southern States and reverse the likely supply-demand shortfall in the South. In Victoria, explorer Lakes Oil estimates to have material conventional gas reserves that do not require fracking. In New South Wales, the development of Santos' onshore Narrabri project could produce up to 50 PJ a year. However, moratoria and regulatory restrictions in Victoria, NSW and Tasmania are impeding or preventing onshore exploration and development of these and other potential resources.

In contrast, gas production in Queensland has surged following the construction of the LNG projects. This is set to be further boosted by the announcement on 1 December 2017 that Arrow Energy[8] has entered into a 27-year GSA with the QGC project.[9] This is a very significant development for the East Coast Gas Market, which will result in the development

[8] Arrow Energy is a 50-50 joint venture between Shell and PetroChina.

[9] QGC project is a joint venture involving Shell, CNOOC and Tokyo Gas.

of over 6,000 PJ of Arrow Energy's gas reserves in the Surat Basin. First gas production is anticipated around 2020 and could potentially ramp up to 240 PJ per annum.[10]

This deal will very likely result in additional quantities of gas being supplied to domestic users, although the extent of this is currently unknown. The development of Arrow Energy's reserves also requires significant investment and it is unlikely that this development would have taken place in the short to medium term in the absence of a long-term GSA with an LNG exporter to underpin this investment.

There are a number of other potentially large sources of future gas supply in Queensland, which could be sanctioned in the coming years. Likewise, there are potentially large unconventional gas resources in the Northern Territory. However, the current moratorium on hydraulic fracturing in the Northern Territory is putting the prospect of these developments in doubt.

While gas from Queensland and potentially the Northern Territory could be transported into the Southern States to address the southern shortage, these sources of supply are located quite far from the southern demand centres. Given that gas needs to be transported long distances across multiple pipelines to reach end users, it is likely that access to reasonably priced pipeline capacity and storage will be important.

However, pipeline capacity constraints on key north to south transportation routes are currently limiting the ability of some market participants to transport gas into the Southern States. Further, the cost of transporting gas from Queensland to the Southern States is currently around $1.85–2.45/GJ, while the cost of transporting gas from the Northern Territory could be in excess of $5/GJ. Further, if viable, an LNG regasification terminal could be an alternative form of transport for bringing additional gas into the Southern States.

How gas is traded and moved around has changed

Previously, the trade of gas mostly occurred using long-term bilateral GSAs. While these are still predominantly used, market participants are now increasingly entering into multiple GSAs with different counterparties and some are taking advantage of the AEMO-operated wholesale markets to manage their portfolios and procure some or all of their gas requirements.

The way gas is being transported across the East Coast Gas Market is also changing. The East Coast Gas Market's transmission system is no longer a series of point to point pipelines, but rather it works as an integrated network and storage provider. Many gas pipelines have become bidirectional and gas increasingly flows across multiple pipelines to reach its destination.

Whereas historically ownership of pipeline capacity was predominantly the domain of the retailers, there is now a far greater range of market participants seeking access to different pipeline services for the purpose of delivery and storage of gas. This includes producers, aggregators as well as C&I users who are seeking to achieve greater flexibility in their choice of gas suppliers.

These developments necessitate an increase in flexibility and ease of access to, and use of, infrastructure services. Significant reforms are currently underway to facilitate a greater level of secondary capacity trading and help market participants gain access to unutilised capacity in contractually congested pipelines, increasing efficient use of pipelines. The ACCC expects these reforms should increase flexibility and drive prices below the monopoly levels observed in the ACCC's 2015 inquiry.

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[10] Arrow Energy, *Arrow Energy agrees deal for Surat Basin reserves*, Media release, 1 December 2017, https://www.arrowenergy.com.au/__data/assets/pdf_file/0004/23638/Arrow-Energy-GSA-media-release.pdf

There is also considerable capital investment currently being made or considered to expand the East Coast Gas Market transmission network. The Northern Gas Pipeline is being built to connect the Northern Territory to the East Coast Gas Market, with a second pipeline being considered. A number of pipelines are being considered in Queensland to connect the Galilee and Bowen basins to the East Coast Gas Market, while a feasibility study is being conducted on a pipeline linking Western Australia to the East Coast Gas Market.

Despite contractual congestion on key pipelines linking Queensland to the Southern States, capacity expansions of these pipelines have not yet occurred, which may be due to market uncertainty associated with the future supply-demand balance and gas prices. While some market participants may be willing to underwrite a pipeline expansion by entering into a five or 10 year gas transportation agreement, the fact that many C&I users currently prefer to enter into much shorter GSAs can make this investment risky, particularly for new entrants into the East Coast Gas Market.

There are currently few storage facilities that are providing third party access to storage services. However, the biggest one of these in the Southern States, the Iona underground gas storage facility, is expanding its capabilities to deliver gas over the southern peak demand period. If gas needs to move from north to south and pipeline congestion during peak periods continues, the availability of reasonably priced access to storage facilities could become increasingly important.

Overall, there is promising progress for the provision of gas infrastructure services, although further developments may be needed to improve availability and access to both pipeline capacity and storage to facilitate more market entry and drive efficient supply of gas.

The factors that are driving domestic prices have changed

Prices in the East Coast Gas Market have historically been low by international standards. However, a combination of increasing production costs and exposure of domestic markets to international LNG markets has put an upward pressure on domestic prices.

As cheap sources of gas are depleted, new sources that are brought online will likely have higher costs of production. The lifecycle cost of coal seam gas (CSG) produced in Queensland is likely to be higher for many producing areas than conventional gas production due to the nature of CSG production. This raises the ‘floor price’ of firm gas supply.

With the construction of the Queensland LNG facilities, domestic prices are now influenced by the higher and more volatile international LNG and oil prices. The current oversupply in the LNG market is keeping LNG spot prices relatively low by historical standards, so if these prices increase in the future, domestic gas prices are likely to increase further with them.

Overall, international LNG prices are likely to be a key and continuing influence on domestic East Coast Gas Market prices.

Future work of the Inquiry

This is the second interim report of this Inquiry, which will operate for three years, with a final report due in April 2020.

As well as continue to update on issues covered in this report, future reports of the Inquiry will cover:

- producer-based and retailer-based invoiced gas price series (as reported in the September 2017 report)
- conditions for, and pricing of, access to transportation and storage services
- retailer pricing, costs and margins

- improvements to market transparency and consistency of reporting.[11]

As part of the broader focus on transparency, over the next few months we will consult on an LNG netback price series (see chapter 6), which may result in the ACCC commencing publishing an LNG spot netback price series from around the first quarter of 2018.

The ACCC will continue to make market information available as appropriate and expects to produce the next interim report towards the end of the first quarter of 2018.

[11] In keeping with the Prime Minister's March 2017 announcement, the ACCC will be working on this with the Gas Market Reform Group.

1. Supply outlook for 2018 and 2019

1.1. Key points

- The supply-demand outlook for the East Coast Gas Market in 2018 has improved since the ACCC's September 2017 report. There is now a lower likelihood of a supply shortfall, although the supply-demand balance remains tight. Under AEMO's expected domestic demand forecast there no longer appears to be a shortfall and under AEMO's upper band forecast, the estimated shortfall has reduced from 108 PJ to 33 PJ.[12]
- The supply and demand balance for 2019 has also improved from what AEMO forecast in September 2017. There is no shortfall projected under AEMO's expected demand forecast and under AEMO's upper band domestic demand scenario, the estimated shortfall is 24 PJ (compared to AEMO's previous estimate of 102 PJ).
- The improvements in the outlooks for 2018 and 2019 are attributable to slight increases in forecast production by some of the key producers in the east coast, but more significantly, reduced export forecasts by the LNG projects in Queensland.
- Since the September 2017 report, the LNG projects have diverted significant quantities of gas originally intended for export to the domestic market. Previously, the LNG projects had forecast to sell up to 63.4 PJ of gas on the international LNG spot markets in 2018.[13] This has since been revised down to 34 PJ. The LNG projects have also revised down the quantity of gas required to meet their long-term LNG contractual commitments and feed gas requirements from 1251 PJ to 1217 PJ.
- The LNG projects have offered significant quantities of gas to the domestic market, primarily to retailers and aggregators. However, only a small percentage of offers have been made to users in the Southern States.
- As discussed in the September 2017 report, producers in the Southern States are forecast to produce insufficient gas in 2018 to meet forecast demand in the Southern States in 2018 due to natural decline of major known gas resources and no new supplies expected in 2018. This means southern users will need to rely on Queensland gas.
- The GBJV–the biggest producer in the Southern States–is expected to significantly drop its production in 2018. After reaching record production levels in 2016 and 2017, the GBJV is expected to reduce its production to 2011-15 levels as it transitions from its legacy fields to newer gas fields that contain higher impurity gas and which require additional levels of processing.

1.2. The supply and demand outlook for 2018 has improved

In September, the ACCC projected a supply shortfall in the East Coast Gas Market in 2018 of up to 55 PJ under AEMO's expected domestic demand forecast, and up to 108 PJ under AEMO's upper band domestic demand forecast.

On 3 October 2017, in response to this, the LNG projects in Queensland signed a Heads of Agreement, in which they committed to offer sufficient gas for 2018 and 2019 to meet the expected shortfalls, through the good faith offering of gas to the domestic market on reasonable terms. The LNG projects also committed to offering gas to the Australian

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[12] The ACCC has relied on AEMO's forecasts of domestic demand in estimating the potential of a shortfall, based on data from its September 2017 GSOO. AEMO's expected domestic demand forecast represents the lower limit of its domestic demand forecast. Upper band domestic demand represents the upper limit. AEMO has described the lower limit of its forecast domestic demand band as what it regards to be the 'most likely to occur' demand, whereas the upper limit of its forecast demand band allows for the occurrence of uncertain but feasible conditions that could increase gas demand.

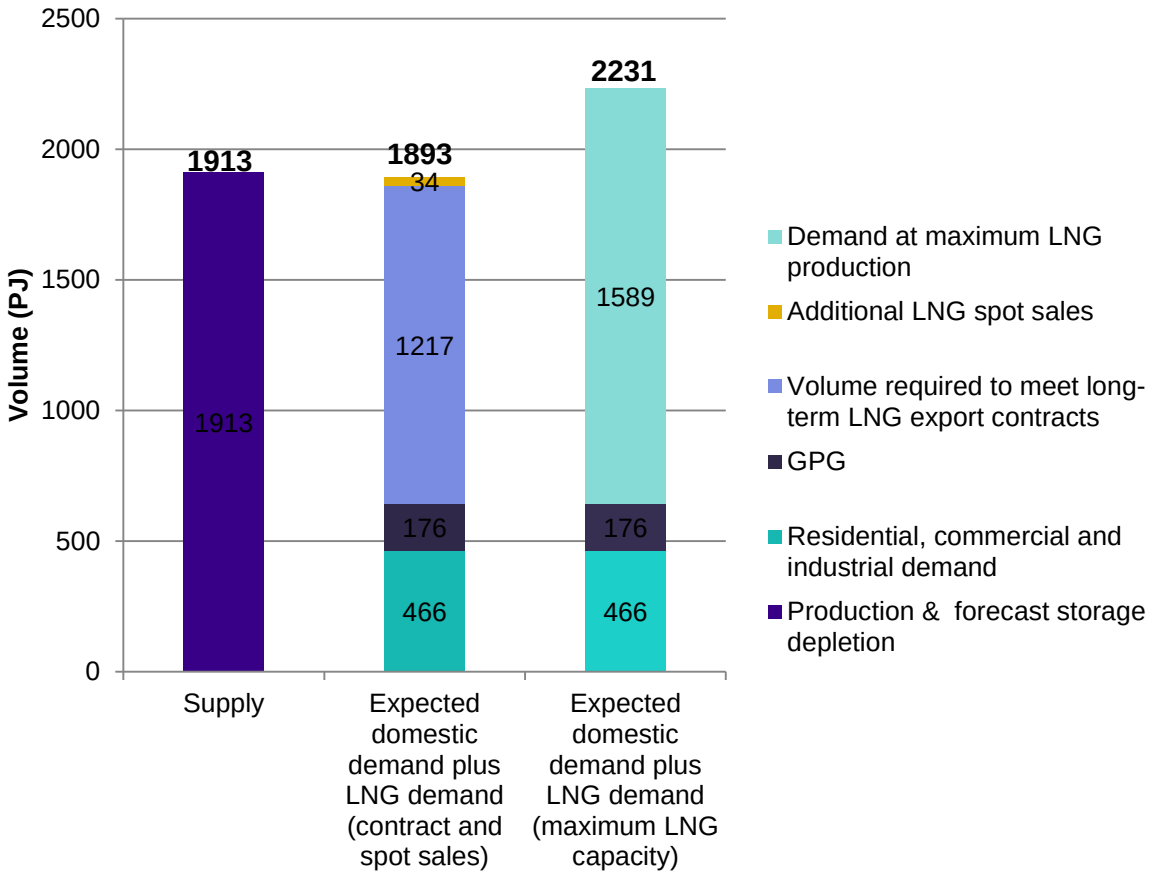
[13] ACCC, '*Gas Inquiry 2017-2020: Interim Report',* September 2017, p.10.

domestic gas market on competitive terms, before offering uncontracted gas to the international market.

Chart 1.1 shows the updated supply and demand outlook for 2018. It shows total forecast supply (production plus storage depletions) against two estimates of demand–total expected demand (being domestic demand plus the quantities of gas required by the LNG projects to meet their long-term contractual commitments and forecast LNG spot sales), and total maximum demand (being domestic demand plus the quantities of gas required by the LNG projects to run their trains at full capacity).

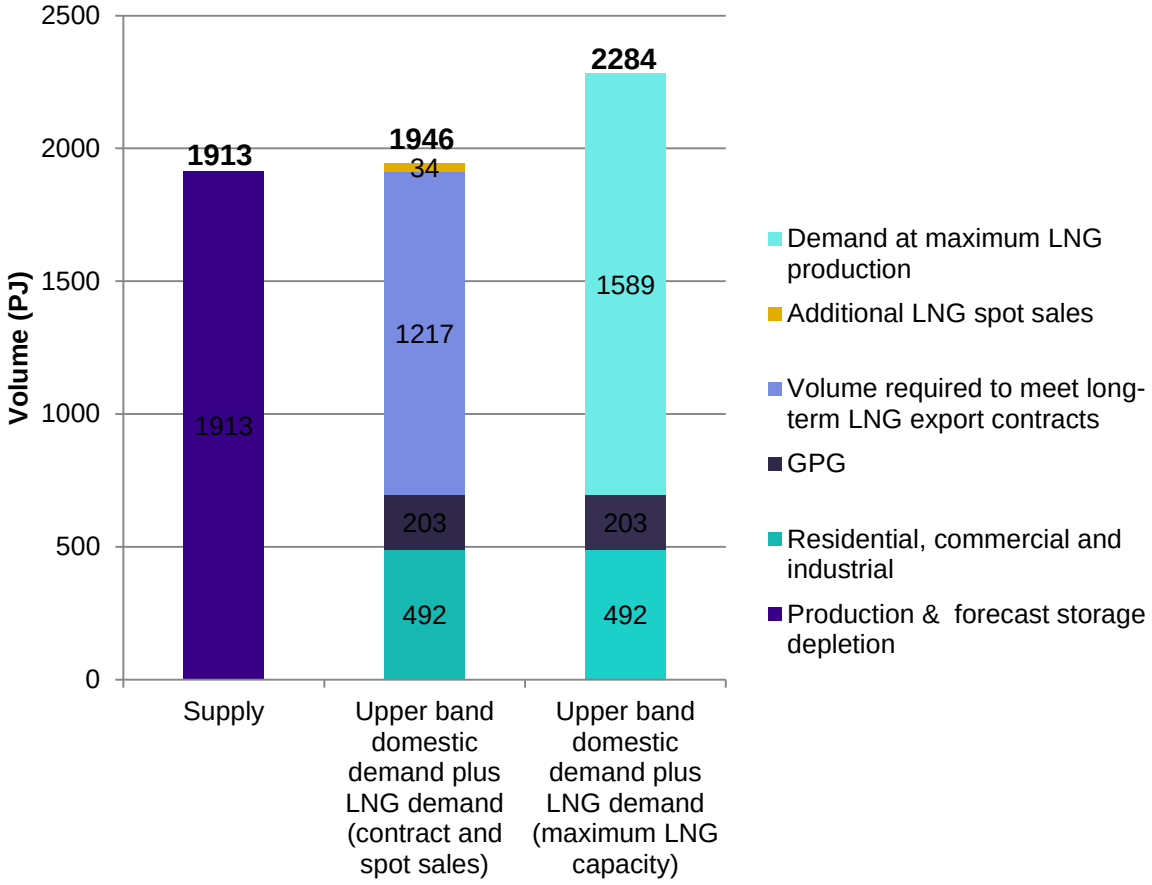
Chart 1.2 shows total forecast supply against total expected demand and total maximum demand based on AEMO's upper band forecast.

Chart 1.1–Forecast supply-demand balance in the East Coast Gas Market (excluding Northern Territory) for 2018 (based on AEMO's expected domestic demand)



Source: ACCC and AEMO data.

Chart 1.2–Forecast supply-demand balance in the East Coast Gas Market (excluding Northern Territory) for 2018 (based on AEMO's upper band domestic demand)



Source: ACCC and AEMO data.

The charts show that there is now a lower likelihood of a supply shortfall in 2018. There is no longer a shortfall expected under AEMO's expected domestic demand scenario and the estimated shortfall has reduced from 108 PJ to 33 PJ under AEMO's upper band domestic demand scenario. This is in large part due to increases in forecast production by some of the key suppliers in the east coast but more significantly, changes in export demand by the LNG projects.

Since the release of the September 2017 report, the LNG projects forecast to sell 29 PJ less gas on the international LNG spot markets and have revised down their long-term LNG contractual commitments, including feed gas requirements, by 34 PJ. While these revised forecasts do not mean the total pool of forecast supply for 2018 has substantially changed, it does mean that more gas is likely to be available for domestic use.

The supply and LNG demand data reflected in the charts above is based on information obtained directly from producers. Forecast production only includes production from 2P reserves and does not include production from contingent or undiscovered resources. These resources are highly uncertain. While these resources would increase the overall supply pool if realised, the quantities of contingent and undiscovered gas forecast for production in 2018 are not material and would be unlikely to have a substantial effect on the supply and demand outlook for the East Coast Gas Market in 2018.

Further, charts 1.1 and 1.2 do not include all forecast storage depletion, or take into account any forecast storage injection. Only quantities expected to be withdrawn from the Roma

Underground Gas Storage, Moomba and Silver Springs storage facilities over 2018 have been included in the supply forecast. Potential depletion of Iona Storage (the other significant storage facility in the east coast) may be able to provide an additional 5 PJ of gas or more to the market depending on its operation.[14]

Since the ACCC's September 2017 report, a total of about 61 PJ of gas has been contracted by east coast gas producers for the supply of gas in 2018–a large proportion of which is attributable to the LNG projects (discussed further below). Retailers and aggregators have contracted 32 PJ of gas to large domestic C&I users and GPGs for 2018 since September.

Even with more offers in the market and the LNG projects diverting more gas domestically, the supply and demand outlook for 2018 continues to represent a tight market. There continues to be the risk of a potential shortfall if forecast production is not realised or domestic demand is higher than forecast.

While most of the forecast gas production for 2018 is from well-known, developed areas, about 5 per cent is from less certain, undeveloped areas–projects which may require additional investment before production can commence.

On the demand side, gas is playing a more critical role in the electricity market, and GPG is likely to have an increasing impact on the level of domestic gas demand. The level of GPG demand is more volatile than other categories of domestic demand (for example, residential and industrial demand) because it is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, renewable generation investment and unexpected retirement of generation or unplanned outages). To some extent, AEMO's upper band domestic demand scenario takes into account this uncertainty, demonstrating the higher end estimate of GPG demand in conditions where there is increased reliance on gas.

1.3. The likelihood of a supply shortfall in 2019 has also reduced

The ACCC focused on the supply and demand outlook for 2018 in its September 2017 report. In this report, we also consider the outlook for 2019. In September, AEMO had forecast a supply shortfall of up to 102 PJ in 2019.[15] Since then, it appears the supply-demand outlook has improved.

Chart 1.3 shows the supply-demand outlook for 2019. It shows total forecast supply (production plus storage depletions) against total expected demand and total maximum demand.

Chart 1.4 shows total forecast supply against total expected demand and total maximum demand based on AEMO's upper band demand forecast.

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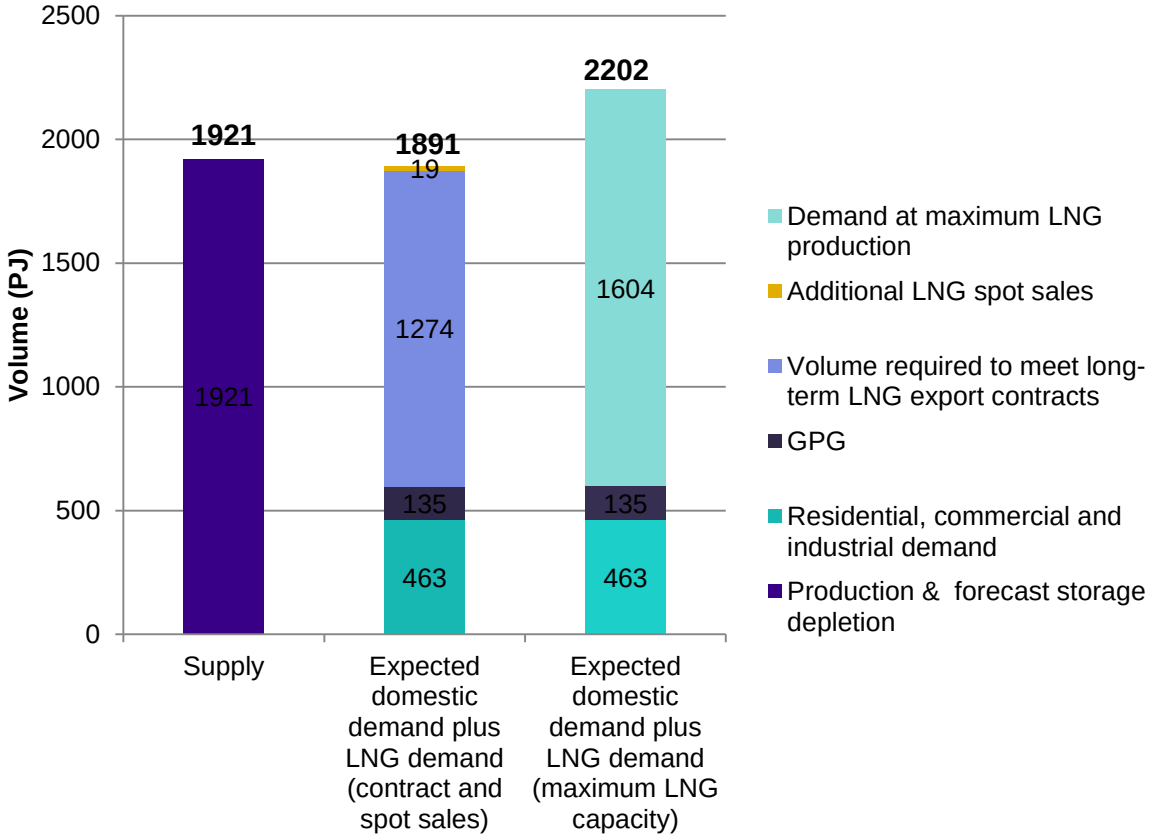
[14] The estimated Iona amount is based on the current refill rate which suggests it may be around 18 PJ full by Dec 31 2017, which is a 5 PJ higher level than the Iona storage was at the end of 31 December 2016. Iona gas storage information is visible on the bulletin board www.gasbb.com.au.

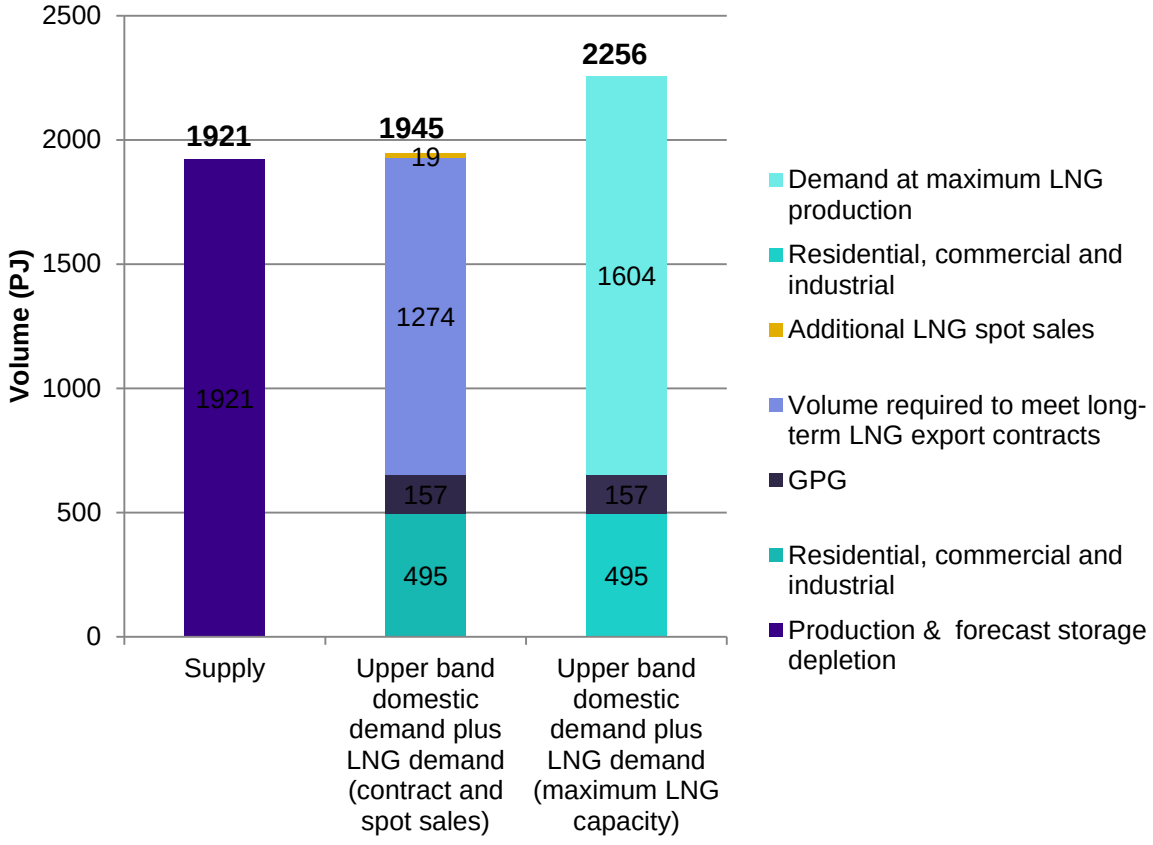
[15] AEMO, '*Update to Gas Statement of Opportunities',* September 2017, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities---Update.pdf.

Chart 1.3–Forecast supply-demand balance in the East Coast Gas Market (including Northern Territory) for 2019 (based on AEMO's expected domestic demand)



Source: ACCC and AEMO data.

Chart 1.4–Forecast supply-demand balance in the East Coast Gas Market (including Northern Territory) for 2019 (based on AEMO's upper band domestic demand)



Source: ACCC and AEMO data.

As shown in the charts, there is no longer expected to be a shortfall in 2019 under AEMO's expected domestic demand scenario. Previously, AEMO had estimated a shortfall of up to 48 PJ. Under AEMO's upper band domestic demand scenario, there is estimated to be a shortfall of 24 PJ (compared with AEMO's previous estimate of 102 PJ).

Based on information provided to the ACCC throughout this Inquiry, the reduction in the shortfall estimates can be attributed to the same reasons as those that have affected the 2018 supply and demand outlook–increases in forecast production from some of the key suppliers but mainly revised export forecasts, which have decreased export demand. The LNG projects expect to export about 54 PJ less in 2019 than initially reported to the ACCC in July and September this year.

The supply forecast for 2019 includes gas supply from the Northern Territory. As discussed further in Chapter 5, the Northern Territory will be connected to the East Coast Gas Market once construction of the Northern Gas Pipeline (NGP) is complete. The NGP is expected to flow gas from late 2018, and is expected to have the capacity to transport up to 35 PJ of gas per annum.[16] The values associated with Northern Territory gas that have been included in the supply forecast reflect the quantity of gas expected to flow to the east coast based on information provided to the ACCC.

[16] Jemena, '*Northern Gas Pipeline: Draft Environmental Impact Statement'*, August 2016, https://jemena.com.au/documents/pipeline/negi/chapters/1-introduction.

As with charts 1.1 and 1.2, the charts in this section only include forecast production from 2P reserves. They do not include production from contingent or undiscovered resources. There is currently 47 PJ of gas forecast to be produced from contingent and undiscovered gas resources in 2019. While these sources of gas supply are highly uncertain as they depend on the economics of development, if this production is realised, it would contribute additional quantities of gas to the East Coast Gas Market.

Only forecast storage depletion from the Roma Underground Gas Storage and Moomba storage facilities over 2019 have been included in the supply forecast for 2019. Depending on the operation of the Silver Springs and Iona storage facilities in 2019, there could be additional quantities of gas available to the market.

1.4. The LNG projects have diverted significant quantities of gas into the domestic market

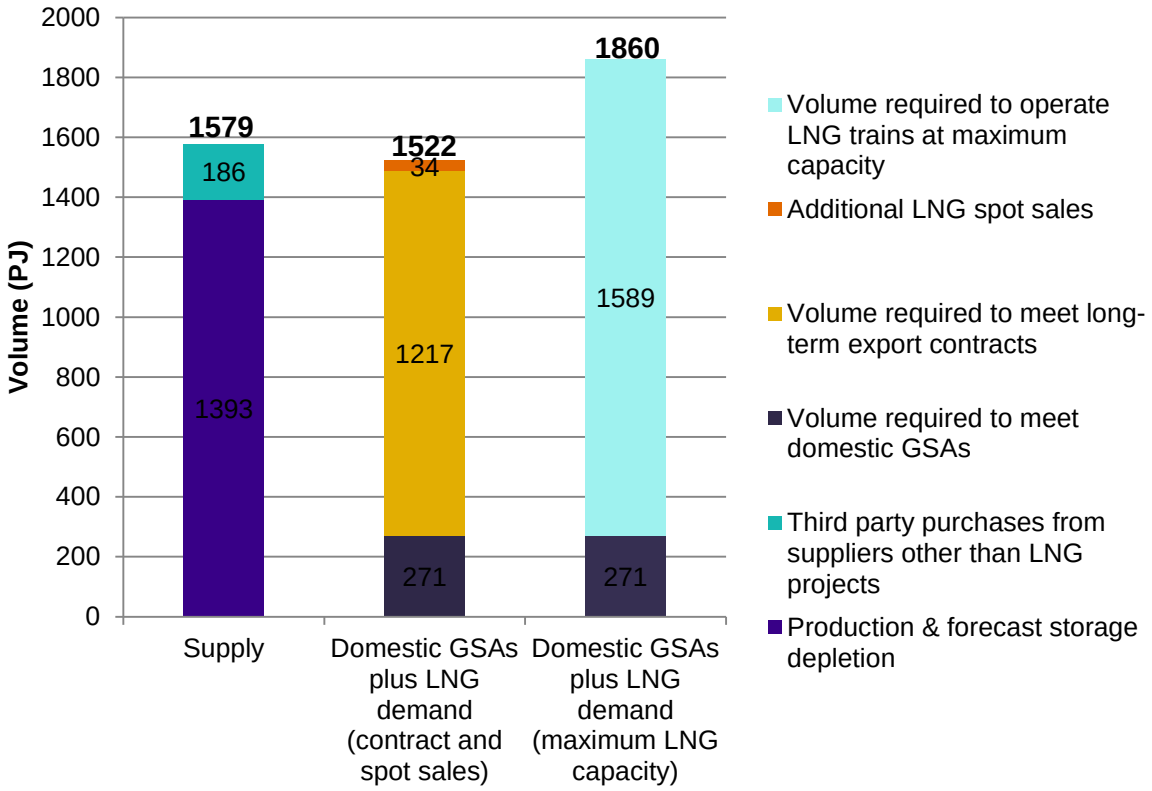
As noted in the September 2017 report, the LNG projects have been increasing their participation in the domestic market. During the year, APLNG had diverted gas to the domestic market during planned outages. QGC had effectively diverted gas originally intended for LNG export to the domestic market. GLNG and Santos had entered into an agreement with Engie for 15 PJ of gas, as well as announced that they would supply 30 PJ of gas to the domestic market over 2018 and 2019 using gas that would otherwise have been exported as LNG.[17]

The ACCC has continued to observe active efforts by the LNG projects to increase their participation in the domestic market, particularly following their commitments to government.

Chart 1.5 shows the updated supply-demand balance of the three Queensland LNG projects for 2018, while chart 1.6 shows their supply-demand balance for 2019.

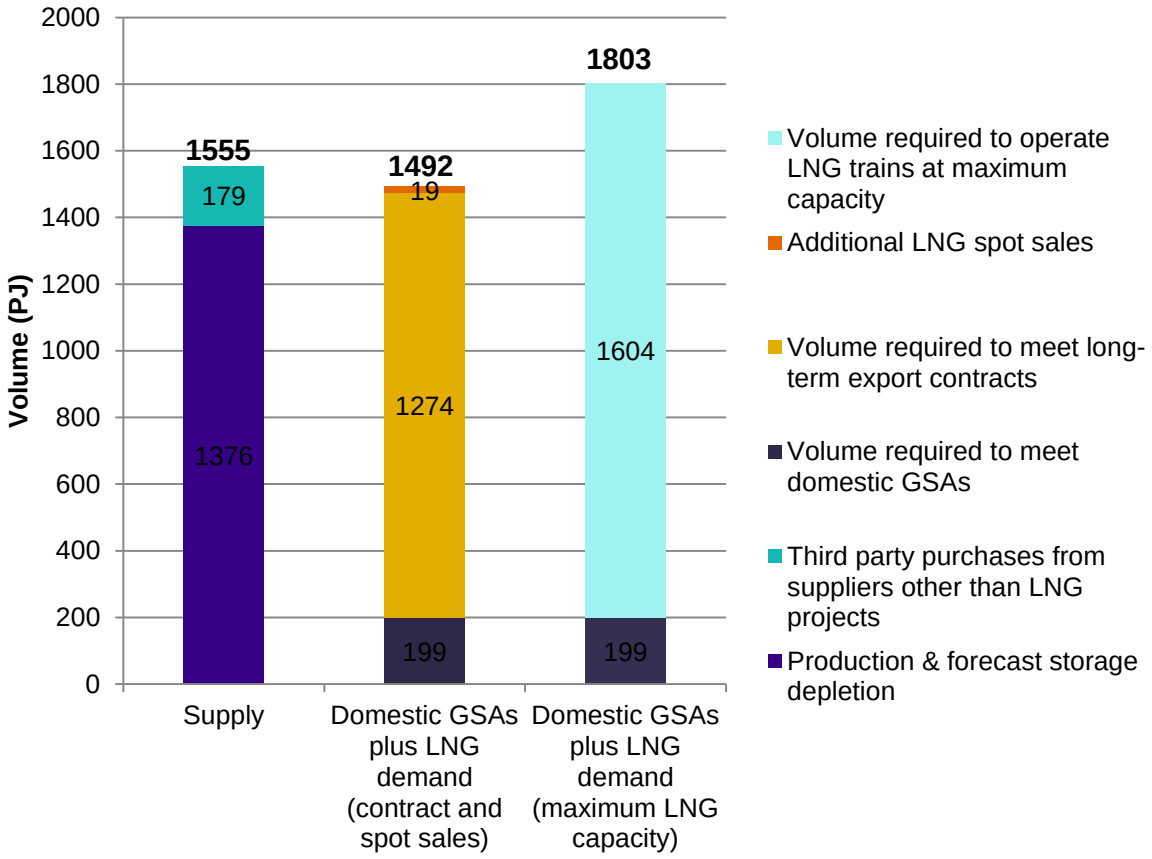
[17] ACCC, '*Gas Inquiry 2017-2020: Interim Report',* September 2017, p.38

Chart 1.5–Forecast supply-demand balance of the Queensland LNG projects for 2018



Source: ACCC data.

Chart 1.6–Forecast supply-demand balance of the Queensland LNG projects for 2019



Source: ACCC data.

Note: the quantity required to operate LNG trains at maximum capacity differs from 2018 due to differences in feed gas adjustments made to account for planned maintenance.

Charts 1.5 and 1.6 show that for both 2018 and 2019, the LNG projects have sufficient gas to meet their existing domestic and LNG export contractual commitments and forecast LNG spot sales.

For 2018, the total forecast supply has increased from 1569 PJ to 1579 PJ since the September 2017 report due to upward revisions of gas production forecasts. There has also been a reduction in LNG contractual and feed gas requirements from 1251 PJ to 1217 PJ and a decrease in forecast LNG spot sales by 29 PJ as a result of more gas being diverted to the domestic market. The LNG projects are still forecasting to sell 34 PJ on the international LNG spot markets in 2018.

Contractual commitments between the LNG projects and domestic buyers for supply of gas in 2018 have increased by 42 PJ since the September 2017 report. Most of the gas offered (and contracted) by the LNG projects has been to retailers, with only a small percentage of gas being offered directly to users in the Southern States. This includes the publicly announced agreement between APLNG and Origin for the supply of 37 PJ of gas in 2018.[18] Origin announced that this gas was needed to meet demand from Origin's existing C&I customers and GPGs.[19]

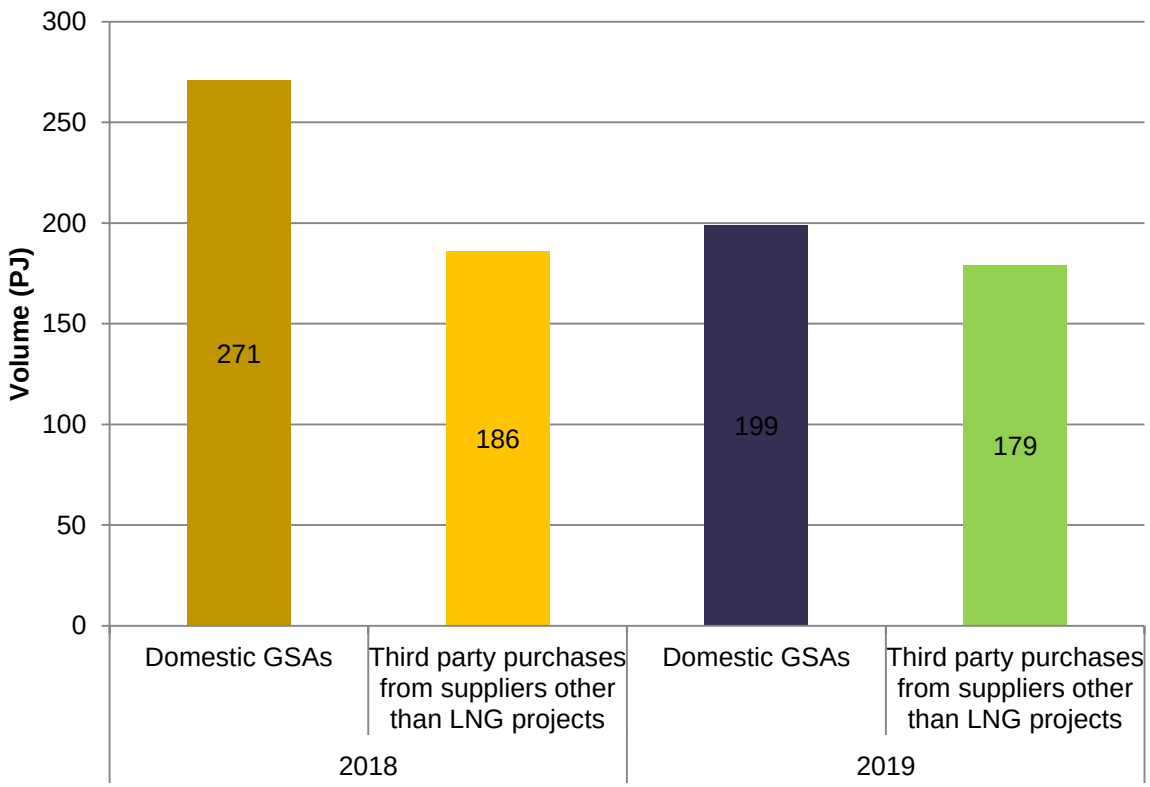
[18] Australia Pacific LNG, Australia Pacific LNG sells additional 41 PJ of gas to domestic market, media release, 26 Oct 2017.

[19] Origin Energy, Origin secures 41 PJs of gas for Australian customers, media release, 26 October 2017.

For 2019, gas production by the LNG projects is currently forecast to be lower by 17 PJ, while the total quantity of exports is forecast to be higher by 42 PJ compared to 2018. The LNG projects are currently forecasting to sell 19 PJ on the international LNG spot markets in 2019.

Chart 1.7 compares the quantity of gas the LNG projects are contracted to supply to the domestic market in 2018 and 2019 with the quantity of gas the LNG projects are contracted to purchase from suppliers other than each other. The chart shows that for both 2018 and 2019, the LNG projects expect to contribute more gas to the domestic market than they expect to take out of the domestic market.

Chart 1.7–Quantities contracted to the domestic market and quantities purchased from third parties by the LNG projects for 2018 and 2019 (excluding transactions between each other)



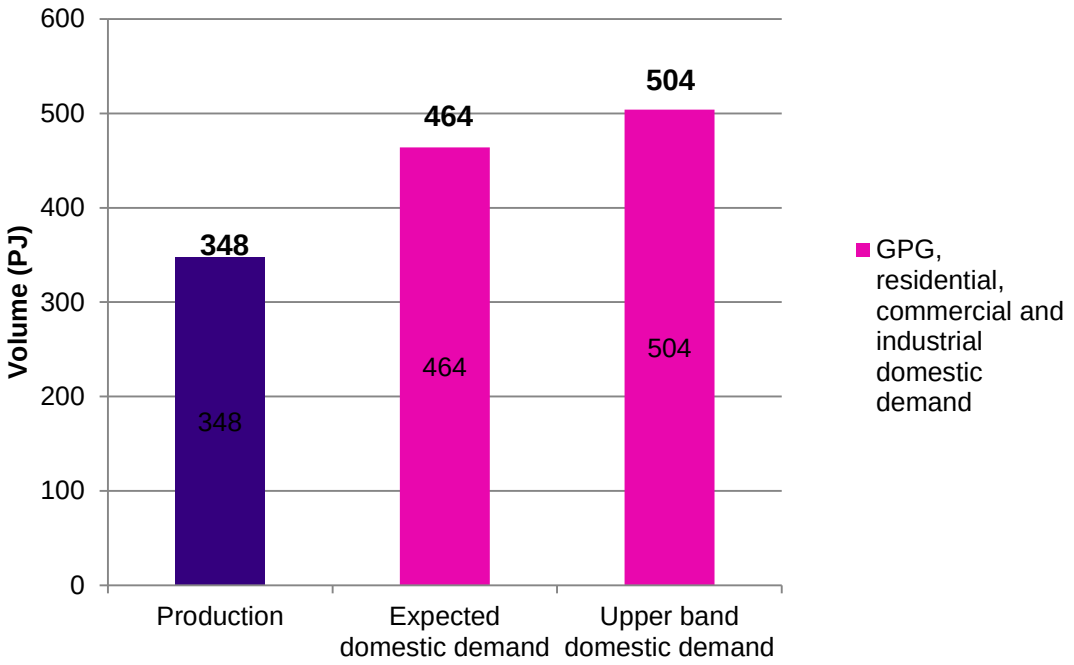
Source: ACCC data.

1.5. The traditional sources of supply in the Southern States are facing a significant decline in production in 2018

As discussed in the September 2017 report, there is insufficient gas production forecast in the Southern States to meet southern demand in 2018. The supply and demand outlook in the Southern States (excluding the Cooper Basin)[20] is depicted in chart 1.8 below and remains unchanged.

[20] The Cooper basin has been excluded from the supply and demand balance for the Southern States as the bulk of production from the basin has been committed to the LNG projects in Queensland.

Chart 1.8–Forecast domestic supply-demand balance in the Southern States for 2018 (excluding Cooper Basin)



Source: ACCC and AEMO data.

In particular, the September 2017 report noted a significant decline in forecast production by the Gippsland Basin Joint Venture (GBJV)–which is currently responsible for more than 80 per cent of gas production from offshore south east Australia.[21] After reaching record production levels in 2016 and 2017 (330 PJ by the end of 2017), the GBJV is expected to reduce its production to 2011-15 levels (244 PJ in 2018) as it transitions from its legacy fields to newer gas fields that contain higher impurity gas and which require additional levels of processing.

The recently completed Offshore South East Australia Future Gas Supply Study found that the GBJV's foundation fields are in decline and that the overall level of production from the GBJV and Longford Gas Plant will continue to decline in the absence of further investment in onshore facilities, or the discovery of new gas resources.[22]

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

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

Esso further explained that increased production by the GBJV is constrained by infrastructure capacity limits. Gas from newer sources of supply, which are smaller in

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21 ACCC, '*Gas Inquiry 2017-2020: Interim Report',* September 2017, p.34.

22 Department of Industry, Innovation and Science, '*Offshore South East Australia Future Gas Supply Study',* November 2017, https://industry.gov.au/resource/UpstreamPetroleum/OffshorePetroleumDevelopment/Documents/Offshore-South-East-Australia-Future-Gas-Supply-Study.pdf, p. 10.

quantities and deeper underground, may have higher levels of carbon dioxide and may require an additional level of gas processing. An example of this is the $5.5 billion dollar Kipper Tuna Turrum (KTT) project, which is now in production.[23] The project is expected to help offset declining production from the legacy gas fields. In 2017, KTT and other recent GBJV investments are expected to provide a third of Longford production, rising to half in 2018.

As explained in the ACCC's 2015 inquiry, gas from the KTT development contains higher levels of mercury and carbon dioxide than historic production fields in the Gippsland Basin, which means it requires processing by a gas conditioning plant.[24] While the Longford Gas Plant has a processing capacity of about 429 PJ per annum, the recently completed Longford Gas Conditioning Plant has a processing capacity of 400 million cubic feet per day[25] or approximately 156 PJ per annum. This means the GBJV will eventually need to invest in an additional gas conditioning plant to prevent a further fall in production as it increasingly relies on higher impurity gas.

Esso informed the ACCC that the GBJV also faces a range of gas system constraints, including pipelines, gas treating capacity, well deliverability and others. Esso also noted that the GBJV is continuing to work on projects to improve its gas system capacity.

The GBJV announced in October that it had established a taskforce of engineers and geoscientists to explore further development opportunities in the Bass Strait.[26] This includes exploring some smaller projects with the potential to add to or accelerate projected 2018 or 2019 production quantities as well as new gas development opportunities that would require significant capital investment. The viability and timing of these projects remain uncertain.

1.6. Queensland is expected to be self-sufficient in 2018

As mentioned above, producers in the Southern States are forecast to produce insufficient gas to meet forecast demand in the Southern States. This means gas users in the south will need to rely on Queensland gas.

Chart 1.9 compares forecast supply for 2018 from Queensland and the Cooper Basin (in South Australia) with forecast domestic and export demand in Queensland. Supply from the Cooper Basin has been included in this chart because, as identified in the ACCC's 2015 inquiry, a significant portion of medium-term production from the Cooper Basin has been committed to the LNG projects in Queensland.[27]

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23 ExxonMobil 2017, Kipper Tuna Turrum, viewed 6 December 2017, http://www.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/kipper-tuna-turrum.

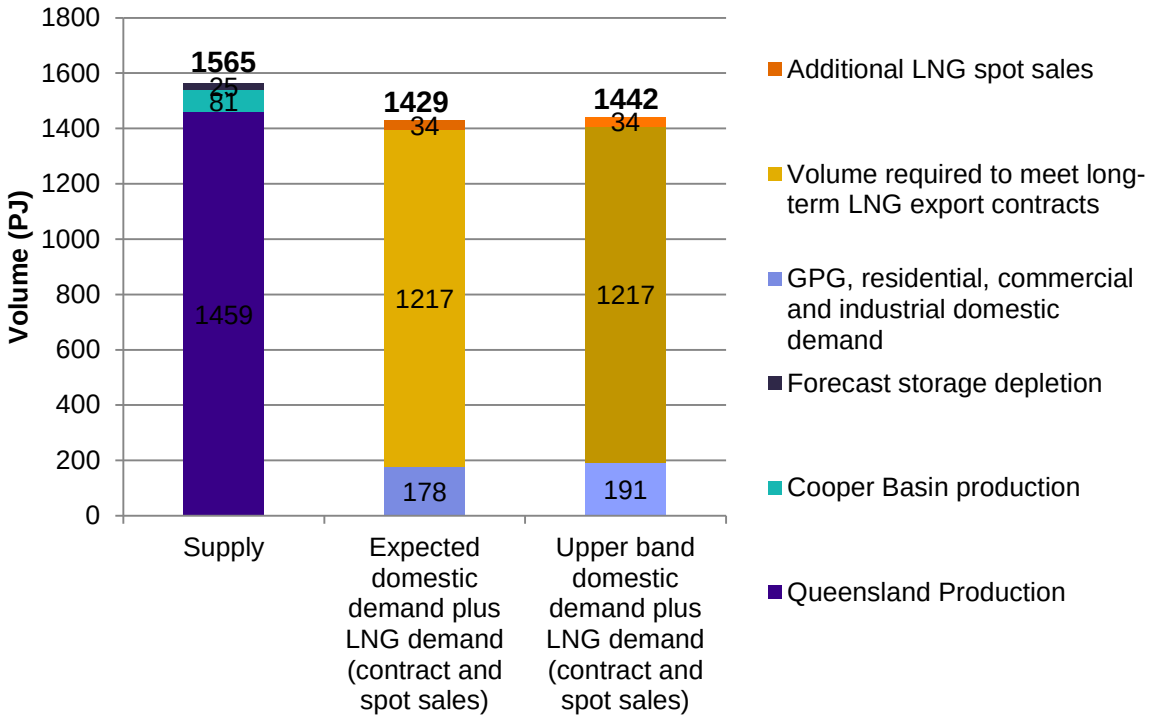
24 ACCC, *Inquiry into the east coast gas market*, April 2016, p.61.

25 BHP, Investment approval for Longford Gas Conditioning Plant, media release, 13 December 2012, http://www.bhp.com/media-and-insights/news-releases/2012/12/longford-gas-conditioning-plant-project-approval.

26 Richard J Owen (ExxonMobil Australia Chairman), Back in the hunt for Gippsland gas, media release, http://www.exxonmobil.com.au/en-au/community/local-outreach/esso-community-news/back-in-the-hunt-for-gippsland-gas.

27 ACCC, *Inquiry into the east coast gas market*, April 2016, p.50.

Chart 1.9–Forecast supply-demand balance in Queensland for 2018 (incl. the Cooper Basin)



Source: ACCC data.

Total supply has increased from 1553 PJ to 1565 PJ since the September 2017 report, which can be attributed to slight revisions to the gas production forecasts of producers in Queensland and the Cooper Basin, as well as increases in forecast storage depletion. The chart does not include contingent and undiscovered gas production forecast for 2018; however, this would not have a significant impact on the supply-demand balance.

Total demand has reduced from 1492 PJ to 1429 PJ under AEMO's expected domestic demand forecast, and from 1505 PJ to 1442 PJ under AEMO's upper band forecast–largely attributable to the LNG projects' revised export forecasts (as discussed at section 1.4).

Chart 1.9 shows that production in Queensland is likely to be sufficient to meet both domestic demand and export demand (both gas required under long-term export contracts and forecast LNG spot sales), even in the absence of gas from the Cooper Basin. This means that gas from the Cooper Basin could be sent south to meet the need of users in the Southern States. As discussed in the September 2017 report, the ACCC had already observed swaps taking place between market participants enabling the Cooper Basin gas that was previously directed to Queensland to flow south.

However, given the difference between forecast production and expected domestic demand in the Southern States (shown in Chart 1.8) is greater than the quantity of gas produced in the Cooper Basin, gas produced in Queensland is also likely to be required to meet the needs of the users in the Southern States. In order for Queensland gas to be able to reach demand in the Southern States, access by the Queensland suppliers to reasonably priced transportation capacity is required. This is discussed in chapter 4.

2. Domestic price outlook for 2018

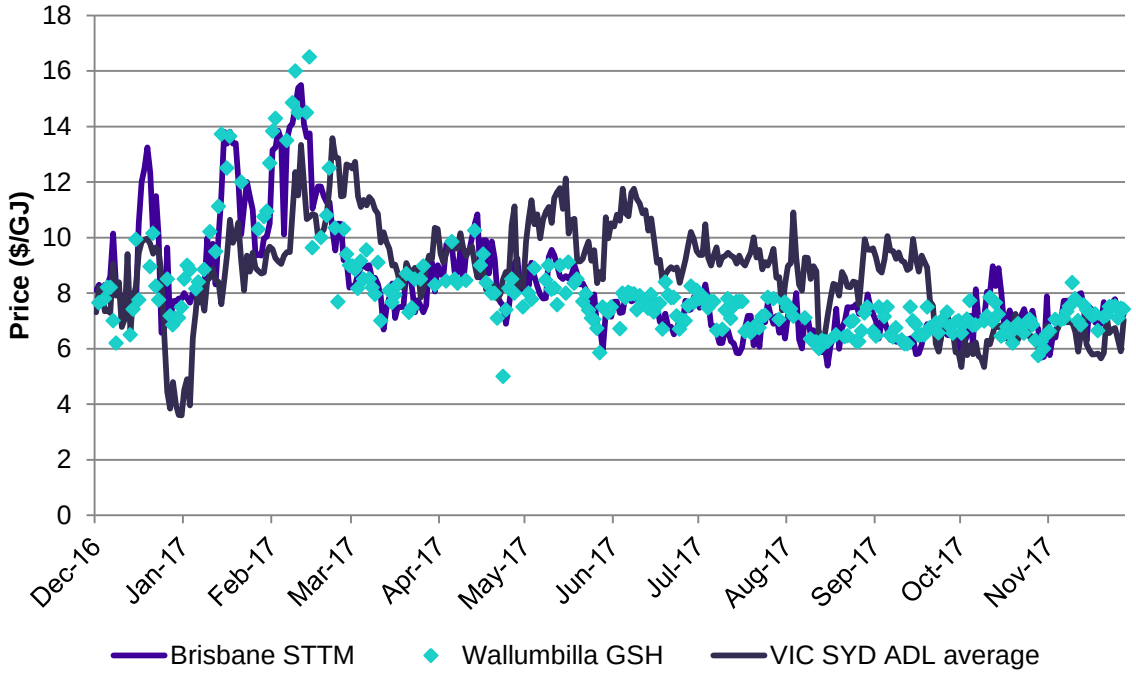
2.1. Key points

- Domestic gas price offers and prices paid in domestic short-term trading markets have fallen since the first half of 2017.
- Average daily prices in Queensland on the Brisbane Short Term Trading Market (STTM) and Wallumbilla Gas Supply Hub fell by 11–12 per cent between the second and fourth quarters of 2017. In the Southern States, average daily prices in the Victorian, Sydney and Adelaide short-term trading markets fell by 34 per cent over the same period.
- Domestic gas prices offered to large C&I users that consume more than one petajoule of gas per annum reached a peak of around $16/GJ in early 2017, while some prices offered to smaller C&I users were even higher. Given these high prices, many C&I users chose to delay contracting for 2018 supply at the time.
- Since July 2017, prices offered to C&I users have eased and have generally been made at $8–12/GJ. Domestic price offers from LNG producers in Queensland tended to be at the lower end of this range, with an average offer of $8.51/GJ. This compares to an overall average offer price across the east coast market of $9.23/GJ.
- As domestic price offers have declined, C&I users have become more willing to enter into GSAs, compared to the first half of 2017, with around a dozen large C&I users having entered into GSAs since June. However, as discussed in chapter 3, many C&I users are still concerned about the level of prices and lack of competition in the East Coast Gas Market.
- In Queensland, wholesale (ex-plant) gas prices agreed with producers for 2018 supply (all of which were with LNG producers) between June and November 2017 have averaged $8.38/GJ. With the inclusion of prices reported by the ACCC in September 2017, and with updated assumptions about key economic parameters, overall average 2018 producer gas prices in Queensland are $8.45/GJ.
- In the Southern States, wholesale gas prices agreed with producers between June and November 2017 have averaged $9.74/GJ (with all prices being agreed with Victorian producers). Including prices reported in September, overall average 2018 producer gas prices in the Southern States are $9.01/GJ.
- Estimated price benchmarks against which the ACCC has compared domestic prices offered and agreed across the market have increased since the September 2017 report, mostly due to higher market expectations around Asian LNG spot prices in 2018. The ACCC has therefore used a range of estimated benchmark prices to assess prices:
    - In Queensland, $5.87/GJ to $7.85/GJ–depending on the point in time the price was agreed.
    - In the Southern States, $6.55/GJ to $9.93/GJ–depending on the buyer's location and the point in time the price was agreed. The upper limit of this range is relevant for users in Victoria and the lower limit for users in South Australia.
- In the period between June and November 2017, prices agreed by producers across the East Coast Gas Market for supply in 2018 are generally at the upper end of, or above, the relevant range of estimated benchmark prices.
- Since June 2017, the gas commodity component of domestic prices set by retailers has averaged $10.26/GJ in Queensland and $9.13–10.28/GJ in the Southern States.

2.2. Prices paid in domestic short-term trading markets

Chart 2.1 shows the daily prices in the Brisbane STTM and the Wallumbilla Gas Supply Hub in Queensland from the end of 2016 to the end of November 2017 as well as the volume weighted average price in the Sydney and Adelaide STTMs and the Victorian Declared Wholesale Gas Market.

Chart 2.1: Daily prices paid in domestic short-term trading markets–December 2016 to November 2017



Source: ACCC analysis of AEMO data

Daily prices on the domestic short-term trading markets have fallen from the levels reported by the ACCC in the September 2017 report. Average prices on the Brisbane STTM and Wallumbilla GSH have fallen from an average of $8.20/GJ and $7.86/GJ in the June quarter to $7.23/GJ and $7.02/GJ (respectively) in the December quarter to date.

In the Southern States, the volume weighted average price across the Victorian, Sydney and Adelaide short-term trading markets fell by 34 per cent over the same period–from $9.78/GJ in the June quarter to $6.41/GJ over October and November.

The ACCC's 2015 inquiry found that the domestic short-term trading markets do not have sufficient traded quantities to enable a significant number of users to rely on them for obtaining substantial portions of their gas requirements. The ACCC found that, while there is scope for these markets to mature, the quantity of gas traded on these markets reflects only around 10–15 per cent of the gas that is bought and sold in the geographic regions served by the respective markets.[28]

Gas buyers in the East Coast Gas Market continue to rely on long-term GSAs to meet their gas requirements. The prices offered and prices agreed under long-term GSAs since the start of 2016 are discussed in the section below.

[28] ACCC, *Inquiry into the east coast gas market*, April 2016, p. 77

2.3. Prices offered and prices agreed under long-term GSAs

This section presents the ACCC's findings on producer and retailer prices agreed under GSAs for 2018 gas supply entered into between January 2016 and November 2017. It also presents findings on price offers that were made over the same period.

2.3.1. Estimated benchmark prices for producers in 2018

The ACCC has had regard to what are appropriate benchmark prices across the East Coast Gas Market for the purpose of assessing whether prices observed under new GSAs and offers for gas supply are consistent with prices that would be expected in a well-functioning market.

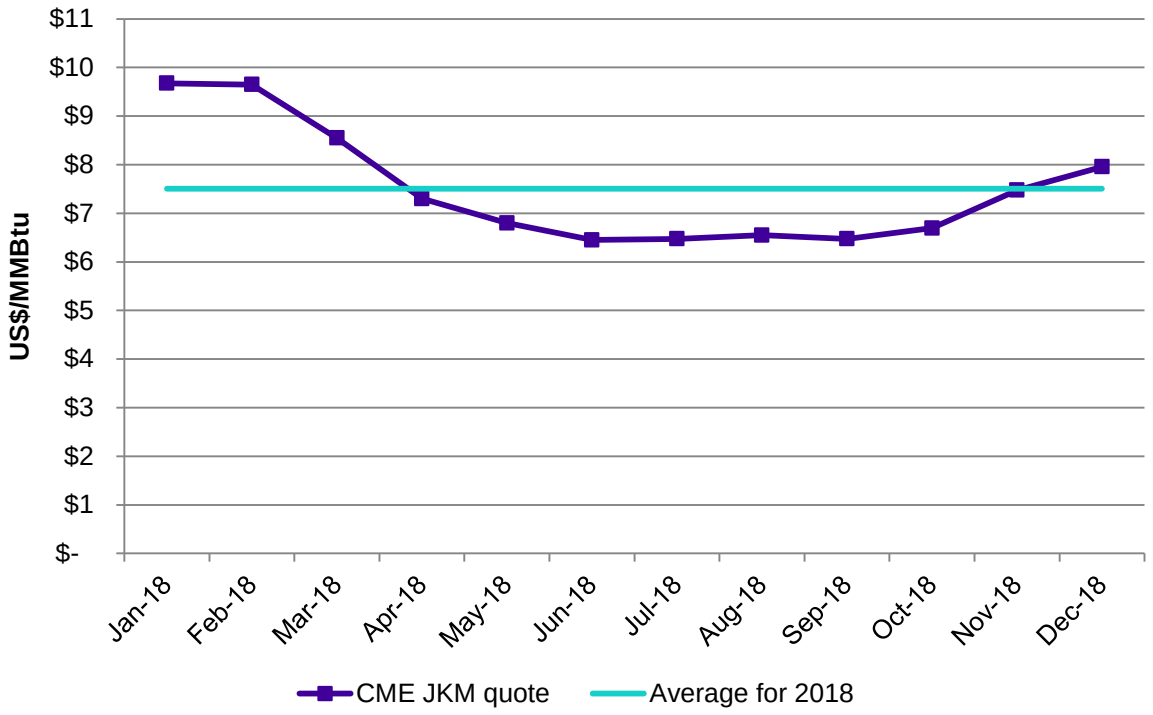
As set out in the September 2017 report[29], for gas supply in 2018 in Queensland, the ACCC considers that the appropriate benchmark price is the higher of:

- the LNG netback price based on average expected Asian LNG spot prices in 2018, and
- the cost of production of the marginal supplier in Queensland.

Asian LNG spot netback price in 2018 and cost of production

The ACCC has estimated an average 2018 Asian LNG netback price based on Chicago Mercantile Exchange LNG futures quotes, which are in turn based on the Platts Japan Korea Marker (JKM) averaged over calendar 2018. As at 24 November 2017 this was US$7.50/MMBtu (see chart 2.2 below).

Chart 2.2: CME Japan Korea Marker (Platts) futures quotes for CY2018



Source: CME, as at 24 November 2017

[29] ACCC, *Gas Inquiry 2017–2020 Interim Report*, September 2017, pp. 67-68.

These LNG futures market expectations show that the seasonally high LNG spot prices over the 2017-18 Asian winter are not at this stage expected to continue after February 2018 nor be repeated the following year, and are expected to fall to below US$7/MMBtu for half of the 2018 calendar year.

Taking the average 2018 LNG spot price of US$7.50/MMBtu and using an exchange rate conversion of AU$1 = US$0.758[30] and an energy conversion of 1 MMBtu = 1.055 GJ, this translates to AU$9.38/GJ. Subtracting average LNG shipping and liquefaction costs (based on information obtained from the east coast LNG exporters) gives an LNG netback price at Wallumbilla of $7.85/GJ.

In the September 2017 report, the ACCC commented that the cost of production of Queensland CSG fields is currently expected to be around $5–6/GJ at the wellhead, based on materials relating to production costs obtained during the ACCC's 2015 inquiry and more general information obtained during this Inquiry.[31] The ACCC has engaged Core Energy as part of this Inquiry to assist it to develop more detailed estimates of the cost of gas production across the East Coast Gas Market. The ACCC expects to report on these estimates in the next interim report.

Estimated benchmark prices for 2018

The ACCC considers that the current benchmark price for domestic gas supply in Queensland in 2018 is the Asian LNG spot netback price at Wallumbilla–that is, $7.85/GJ.

However, the ACCC notes that LNG futures market expectations around Asian LNG spot prices in 2018 have increased since the ACCC's September 2017 report–from around US$6/MMBtu in September to US$7.50/MMBtu towards the end of November. This appears to be due to a range of factors, including increasing demand (both seasonal and because of coal to gas switching in China) and increased coal and oil prices.[32] This has meant that the ACCC's estimated benchmark price for the domestic market has increased commensurately. Further, a decline in the AUD/USD exchange rate over the same period has added to the increase in the benchmark price.

As a result, the 2018 benchmark price used for domestic gas supply in Queensland has increased from AU$5.87/GJ, as noted in the September 2017 report, to the AU$7.85/GJ currently estimated.

This shift has implications for any comparison between prices offered or agreed in the domestic market to estimated benchmark prices over this period. The September 2017 report noted that market expectations around Asian LNG spot prices in 2018 had remained relatively constant since the beginning of 2016. This meant that broad comparisons could be drawn between volume weighted average prices agreed under GSAs entered over the preceding 18 months and benchmark prices estimated for the September 2017 report.

However, given the recent increase in expectations for 2018 Asian LNG spot prices, the ACCC considers that it would be more appropriate to compare prices offered and agreed in the domestic market over the past few months to the range of estimated benchmark prices that has prevailed over the same period. This would account for the fact that some GSAs may have been executed when pricing expectations were lower and some when pricing expectations were higher. Therefore, the ACCC considers that an appropriate benchmark

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30 It is assumed that, consistent with Commonwealth Treasury methodology, the expected AUD/USD exchange rate for 2018 will vary around the current rate. The current exchange rate (as at 24 November 2017) is 75.8 US cents to the Australian dollar (using the average of the preceding five days' exchange rates published by the RBA).

31 ACCC, *Gas Inquiry 2017-2020 Interim Report*, September 2017, p. 67.

32 BP Statistical review of World Energy 2017; Reuters, 'Robust Chinese demand ensures Asian LNG rally has legs', 30 September 2017, https://www.reuters.com/article/us-asia-winter-lng/robust-chinese-demand-ensures-asian-lng-rally-has-legs-idUSKCN1C42BW

price range against which to compare prices offered and agreed for 2018 gas supply in Queensland in the period between June and November 2017 would be $5.87/GJ to $7.85/GJ.

The benchmark prices in the Southern States depend on the supply-demand balance in the Southern States. As discussed in chapter 1, it is still expected that domestic gas buyers in the south will need to contract with Queensland gas producers to meet their 2018 gas requirements and will also be expected to bear the cost of transporting gas from Queensland to their location.

The ACCC has estimated, on the basis of the current prices on major transmission pipelines[33], the average expected cost of transportation in 2018 from Wallumbilla to major demand centres in the Southern States. Adding these estimates to the benchmark price range in Queensland for 2018 (that is, $5.87–7.85/GJ) gives delivered gas prices in each of these locations, as set out in the table below.

Table 2.1: Delivered 2018 gas prices at southern demand centres, based on estimated benchmark prices in Queensland

Demand centre	Transportation cost from Wallumbilla ($/GJ)	Delivered gas prices based on benchmark ranges in QLD ($/GJ)
Adelaide	1.85	7.72–9.70
Sydney	2.07	7.94–9.92
Melbourne	2.45	8.32–10.30

Source: ACCC analysis

While the currently expected supply-demand balance in the Southern States continues, these delivered gas prices would be expected to shape the market price of gas in the Southern States. From the perspective of a producer in the Southern States, this means that the wholesale (ex-plant) price of gas that the producer would expect to receive in a well-functioning market would be the delivered price of gas from Queensland to a particular buyer's location, less the cost of transporting the gas from the producer's wellhead to that buyer's location.

As noted in the September 2017 report, almost all gas production in the Southern States in 2018 is expected to come from producers in off-shore Victoria. Based on recent pipeline operator invoices obtained under this inquiry, the ACCC estimates that the cost of transporting gas from off-shore Victoria to Melbourne, Sydney and Adelaide ranges from around $0.37–1.17/GJ.

Therefore, a benchmark price that producers in the Southern States would be expected to receive at the wellhead would be the delivered price of Queensland gas in the Southern States (being the delivered gas price ranges in table 2.1 above) less an amount to account for transportation, depending on the buyer's location (being $0.37–1.17/GJ). This means that estimated benchmark prices in the Southern States, for gas produced in Victoria, would range from $6.55/GJ to $9.93/GJ. The appropriate benchmark price within this range to compare to prices offered and agreed in the Southern States would depend on both the buyer's location and the point in time the price was offered or agreed.

[33] Using pipeline operator invoices issued in July 2017 – see chapter 4. These transportation cost estimates include an allowance for pipeline losses. The tariffs have been calculated assuming a 100 per cent load factor.

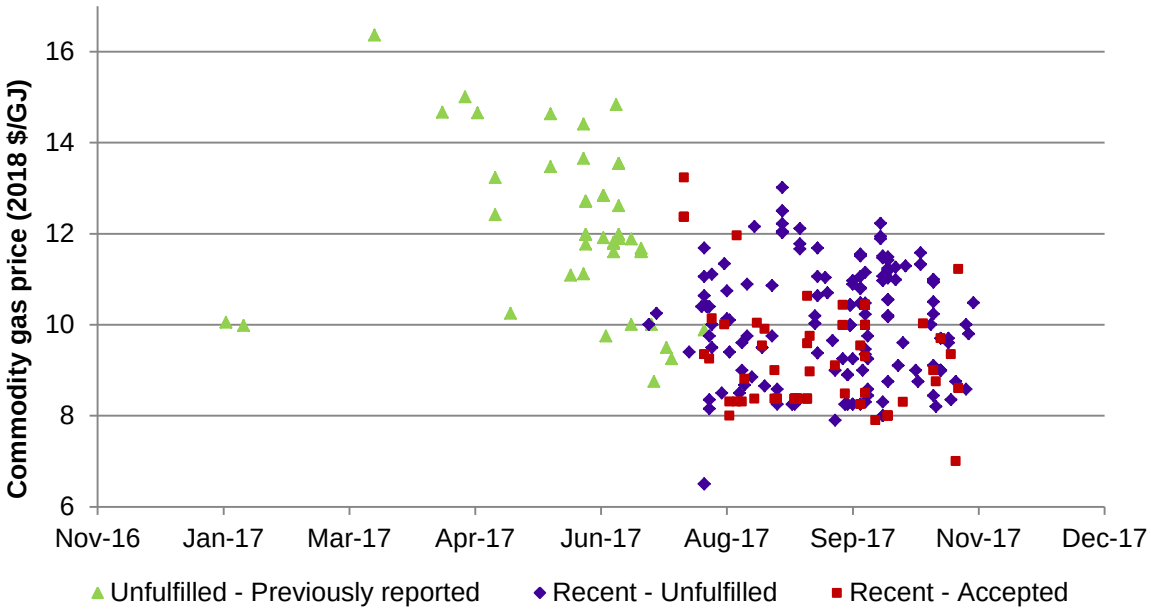
2.3.2. Offers for gas supply in 2018

In the ACCC's September 2017 report, we reported on unfulfilled offers in the East Coast Gas Market. These were written offers for gas supply in 2018 of at least one petajoule per annum that did not result in a GSA by 14 July 2017. For this report, the ACCC obtained information from gas suppliers on all offers made and bids received for gas supply of at least half a petajoule per annum between 14 July and 9 November of this year.

The price offers and bids discussed in this section include offers from and bids to both producers and retailers/aggregators for a range of buyers including retailers, C&I users and GPGs. Consistent with the gas prices presented elsewhere in this chapter, these prices reflect offers and bids made for commodity gas only–that is, not including the cost of transporting gas to the user's end location. It should also be noted that, as in the case of prices under GSAs, offers from retailers/aggregators may include margins and other types of costs. Further, price offers and bids are not all directly comparable, as they may differ on non-price terms such as GSA quantities, take or pay levels, or duration. Some may also reflect seasonal price fluctuations or linkages to prices of other commodities (such as oil) or, in the case of GPGs, electricity prices.

Chart 2.3 below shows the commodity gas prices included in unfulfilled offers that were made by suppliers for 2018 gas supply over the period from 1 January 2017 to 14 July 2017 and all offers made by suppliers subsequently until 9 November 2017. It should be noted that not all price offers in the chart (and those discussed in this section) are for unique combinations of seller and buyer. That is, some offers may reflect follow up offers that were made by the same supplier to the same customer 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 has evolved since the start of 2017.

Chart 2.3: Unfulfilled offers between 1 January 2017 and 14 July 2017 and all subsequent offers up to 9 November 2017 across the East Coast Gas Market



Source: ACCC analysis of offers provided by suppliers

Note: Offers up to 14 July are for annual quantities of at least 1 PJ; offers after this are for annual quantities of at least 0.5 PJ

In September, we reported that unfulfilled offers had shown an increase in price over time since the beginning of 2016, reaching a peak in early 2017 before declining leading into July

2017. Chart 2.3 shows that the price of most offers made in the most recent period to 9 November are in the range $8 to $12/GJ. Recognising the caveat about retailer commodity gas charges and the potential for them to reflect other types of retailer-specific costs, this range is above the ACCC current forecast estimate of the average LNG netback price over 2018 (see section 2.3.1.).

Chart 2.3 also shows that accepted offers tend to be at lower prices than unfulfilled offers. This may reflect instances in which buyers have been able to reject sellers' first offers before negotiating toward, and accepting, a lower price or finding an alternative cheaper source of supply. While recent prices are higher than they were in 2016, they are lower than the highest offer prices observed in the first half of 2017.

Offers and bids for gas supply by LNG producers and other suppliers

There were 207 offers and 143 bids reported to the ACCC by gas suppliers over the period from 14 July 2017 to 9 November 2017. The price range of offers made was $7.90/GJ to $23.96/GJ[34] with a volume weighted average offer price of $9.23/GJ. The price range of bids received was $5.50/GJ to $11.48/GJ with an average bid price of $8.59/GJ.

Charts 2.4 and 2.5 show that the price bands within which most offers were made by LNG producers are similar to the price bands within which most bids were made by buyers to LNG producers. They also show that the average prices of offers and bids are relatively close together.

Chart 2.4: Offers by LNG producers

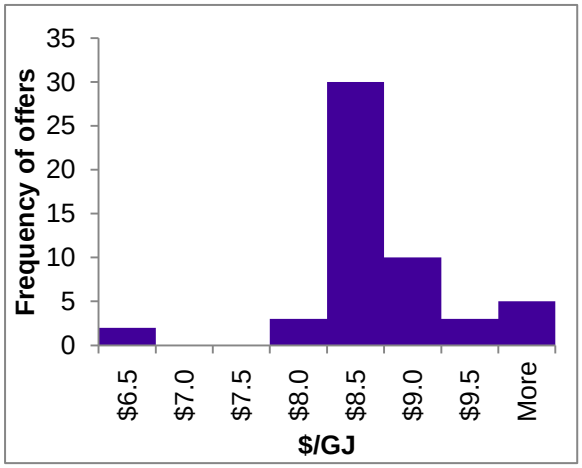
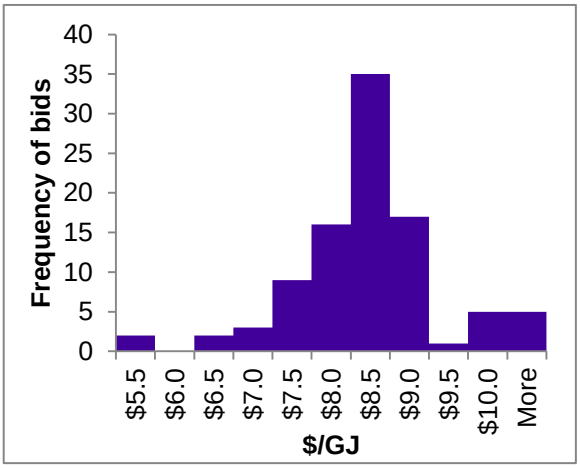


Chart 2.5: Bids to LNG producers



Source: ACCC analysis of offers and bids provided by LNG producers

LNG producers made 54 offers of gas at prices over the range from $6.50/GJ to $10/GJ with the average offer at $8.51/GJ. The bulk of these offers were made to retailers and aggregators who will on-sell gas or use it to power electricity generation. LNG producers also received 95 bids for gas at prices over the range from $5.50/GJ to $11.31/GJ, with the average bid of $8.24/GJ.

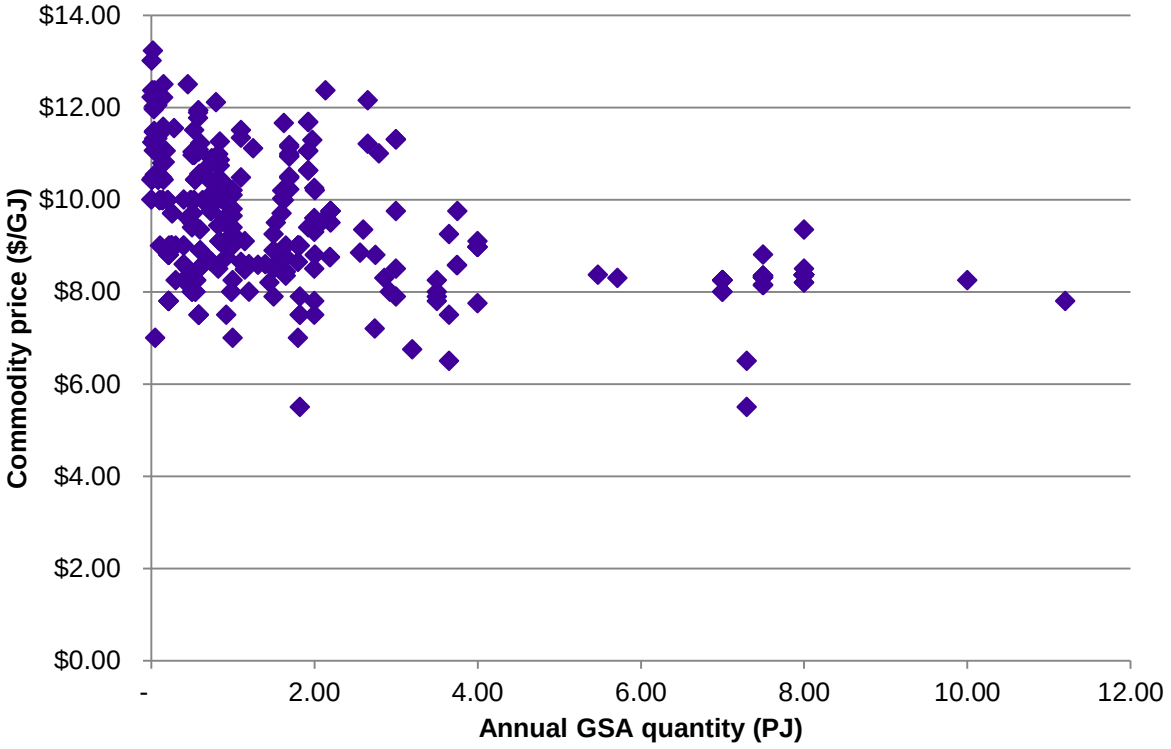
There were 48 bids made to other suppliers (including non-LNG producers, retailers and aggregators) for gas supply in 2018. These bids ranged from $7.18/GJ to $11.48/GJ. Other suppliers made 153 offers in total ranging from $8.00/GJ to $23.96/GJ. However, the ACCC notes that this includes only two offers reported by AGL to the ACCC over this period. The ACCC is seeking additional information to better understand the extent of AGL's participation in the market.

[34] There were a small number of offers above the general range of $8–12/GJ associated with small GSA volumes.

Contract quantity and duration of recent offers and bids

As noted above, offer and bid prices are not all directly comparable. In particular, offers for smaller quantities over longer terms tend to be at higher prices than offers for larger quantities over shorter terms. Chart 2.6 shows that the price of offers and bids over the period from 14 July 2017 to 9 November 2017 appears to be lower for larger GSAs but there is significant variation in price, particularly for smaller GSAs. This trend is consistent with that observed in the September 2017 report, where unfulfilled offers below the median GSA quantity were more expensive than larger offers.

Chart 2.6: Annual GSA quantity (PJ) vs price in ($/GJ) in recent offers and bids

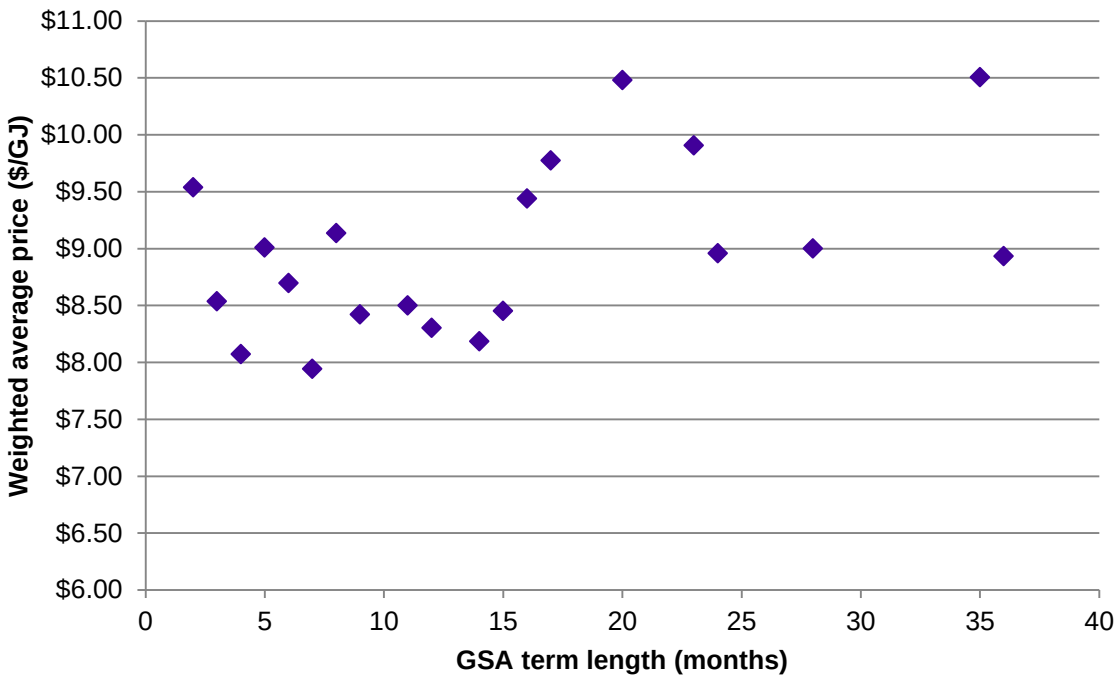


Source: ACCC analysis of offers and bids provided by suppliers

Chart 2.7 shows that, in contrast with the 2017 September interim report, over the period from 14 July 2017 to 9 November 2017, offers and bids made for longer-term GSAs appear to be more expensive than shorter-term GSAs. The chart contains the volume weighted average price of all offers and bids corresponding to GSA durations from 2 to 36 months. The apparent increase in the prices of offers and bids for GSAs with longer duration may be due to a number of reasons:

- expectations of higher future international or domestic prices by the contracting parties
- reduced willingness on the part of suppliers to commit to GSAs for an extended period due to uncertainty over supply as well as future international and domestic prices.

Chart 2.7: Recent offer and bid prices ($/GJ) vs GSA term length (months)



Source: ACCC analysis of offers and bids provided by suppliers

2.3.3. Prices agreed for gas supply in 2018

This section sets out the ACCC's findings on the wholesale gas prices that producers, retailers and aggregators expect to receive in 2018 under GSAs entered into between January 2016 and November 2017 with gas buyers in Queensland and the Southern States.[35]

The gas prices cited in this section have been estimated using the pricing mechanisms specified in each GSA and assumptions relating to key variables such as oil prices, foreign exchange rates and CPI, where relevant.

The ACCC notes that the GSA prices and averages cited in this section are not adjusted to reflect any differences in non-price terms specified in the GSAs, such as take-or-pay levels, loading factors or banking rights. 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.

Prices expected to be paid in 2018 under producer GSAs are compared to estimated benchmark prices for 2018 (which are set out above). However, the ACCC has not compared prices under retailer GSAs with benchmark prices because these may include retailer-specific gas supply costs as well as retailer margins (see chapter 3).

Queensland

Table 2.2 shows volume weighted average gas price estimates for 2018 gas supply based on long-term GSAs (that is, GSAs with a duration of at least one year) entered into in Queensland since January 2016.

[35] The prices reported in this section are based on the wholesale price of gas (sometimes referred to as the ex-plant or commodity price) and do not include the cost of transporting gas to the user's end location. The cost of transportation has been excluded from this analysis (where relevant) to enable a more direct comparison between the prices charged by producers in each basin with the LNG netback price.

These 2018 averages incorporate prices agreed under GSAs that were previously reported in the September 2017 report (which were entered into between January 2016 and May 2017) as well as GSAs entered into between June and November 2017.

Table 2.2: Volume weighted average 2018 wholesale gas prices in Queensland (under GSAs executed since January 2016)[36]

Type of supplier	Volume weighted average gas price ($/GJ)
Producer	8.45
Retailer/aggregator	9.24

Source: ACCC analysis

Table 2.3 below shows volume weighted average gas price estimates for 2018 based on long-term GSAs entered into since June 2017 in Queensland.

All long-term GSAs entered into by producers in Queensland over this period involved LNG exporters supplying gas to retailers or aggregators under transaction notices pursuant to (in most cases pre-existing) 'master GSAs'.[37] These transactions occurred both before and after the Heads of Agreement with Queensland LNG producers.

Of these transactions, some are oil-linked while others have fixed prices. It should be noted that, for the oil-linked transactions, at the time prices were agreed the parties would have held their own expectations about future movements in both oil prices and exchange rates and what this implied for domestic gas prices, which may not reflect actual movements and current expectations about these variables for 2018.

Table 2.3: Volume weighted average 2018 wholesale gas prices in Queensland (under GSAs executed since June 2017)

Type of supplier	Volume weighted average gas price ($/GJ)
Producer	8.38
Retailer/aggregator	10.26

Source: ACCC analysis

The ACCC emphasises that these averages are based on a small number of GSAs. Collectively, only seven producer, retailer and aggregator long-term GSAs were entered into

[36] In all estimates of 2018 GSA prices in this report, the following assumptions were made, where relevant:

- Consistent with Commonwealth Treasury methodology, the expected AUD/USD exchange rate for 2018 will vary around the current rate. The current exchange rate (as at 24 November 2017) is 75.8 US cents to the Australian dollar (using the average of the preceding five days' exchange rates published by the RBA).
- Expected Brent crude oil prices for 2018 are assumed to vary around the relevant monthly futures price discounted by the risk free interest rate. Brent futures settlements quoted as at 24 November 2017 on the Chicago Mercantile Exchange were discounted by the US Treasury yield curve for the same day. The average expected Brent price for 2018 is US$61.28/bbl.
- Based on the historical relationship between Brent crude oil prices and the Japanese Customs Cleared (JCC) crude oil price, the ACCC considers that the Brent price lagged by half a calendar month is an appropriate proxy for the JCC price.
- CPI is assumed to increase by 2.5 per cent year-on-year from 2017 levels, for both Australian and US CPI.

[37] A master GSA is an agreement that provides for a number of key terms and conditions to be agreed and apply to all the transactions conducted under the agreement. In the master supply agreements provided to the ACCC, the actual volumes of gas to be supplied and the price of this gas (and other terms not specified in the master agreement) tend to be agreed separately in 'transaction notices' that are executed by the parties. Transaction notices are made pursuant to the master agreement, but can be used to amend the master agreement if both parties agree.

for 2018 supply in Queensland between June and November 2017. However, as noted in chapter 1, some of the producers' GSAs were for significant quantities of gas.

Producers in Queensland also entered into a number of seasonal short-term GSAs over this period with retailers/aggregators and GPGs–some with supply over winter and some over summer months. The volume weighted average 2018 gas price for these GSAs is $9.32/GJ, significantly higher than the average price under long-term GSAs.

The prices shown in table 2.3 should not be directly compared to the prices reported in the September 2017 report. The prices under GSAs reported in September were estimated on the basis of a different set of assumptions about key economic parameters in 2018. Market expectations around oil prices and exchange rates have changed over recent months and these price movements need to be incorporated into the previous price estimates to enable comparison with expected 2018 prices under GSAs entered into more recently. If this is taken into account, the prices that are expected to be paid in 2018 under recent GSAs would be similar to the prices reported in the September 2017 report.

However, even after this adjustment, the comparison between prices reported in table 2.3 and prices reported in the September 2017 report does not fully reflect the changes in the market conditions observed over the past few months. This is because prices reported in the September 2017 report were largely based on GSAs executed in 2016. As shown in section 2.3.2, prices offered by gas suppliers increased significantly in early 2017 and, as a result, gas buyers were less willing to enter into GSAs at the time. Had those price offers been accepted by the buyers, the prices agreed more recently would have been much lower in comparison.

As discussed in section 2.3.2, since around July 2017, there has been a substantial reduction in the prices offered by suppliers relative to the first half of 2017. Gas buyers have become more willing to accept these offers and this has led to significant quantities of gas being contracted. However, as discussed in chapter 3, C&I users remain concerned about the level of gas prices and the level of competition in the East Coast Gas Market.

Comparison of producer prices in Queensland to estimated benchmark prices

As noted above, all long-term GSAs entered into by producers in Queensland since June 2017 involved LNG exporters supplying gas to retailers or aggregators. Prices agreed for 2018 supply under these transactions ranged $8.30–9.27/GJ, with most prices being at the lower end of this range. All prices agreed with producers over this period are above the upper end of the estimated benchmark price range for 2018 of $5.87–7.85/GJ in Queensland.

The lowest and most recently agreed price was $8.30/GJ in October, which, because of this timing, is somewhat more comparable to the current estimate of benchmark price of $7.85/GJ. In contrast, in another transaction in mid-August, a similar price was agreed (at $8.31/GJ). This price was agreed when, given 2018 LNG spot market expectations at that time, the benchmark price would have been closer to the lower end of the 2018 benchmark price range. Therefore, the difference between the price agreed in August and the contemporaneous benchmark price would have been greater than that of the similar price agreed in October. Both of these transactions were between LNG exporters and retailers or aggregators.

Given the range of prices agreed for supply from the LNG exporters over the period since June 2017, the margins between prices agreed and the benchmark prices that would have prevailed at the time of the transactions vary. Broadly speaking, however, all prices agreed since June 2017 are well in excess of the currently estimated benchmark price for 2018 in Queensland.

However, as noted in the September 2017 report, the ACCC recognises that there may be some coordination costs incurred by LNG producers associated with supplying excess gas domestically compared with selling additional LNG on international markets. The ACCC intends to explore these in future interim reports.

Further, the ACCC notes that it is currently exploring the reasons for differences in commodity gas charges between producers and retailers and will comment on this in a subsequent report.

Southern States

Table 2.4 shows volume weighted average gas price estimates for 2018 gas supply based on long-term GSAs entered into in the Southern States since January 2016. These 2018 averages incorporate prices agreed under GSAs that were previously reported in the September 2017 report (which were entered into between January 2016 and May 2017) as well as GSAs entered into between June and November 2017.

Table 2.4: Volume weighted average 2018 wholesale gas prices in the Southern States (under GSAs executed since January 2016)

Type of supplier	Volume weighted average gas price ($/GJ)
Producer (VIC only)	9.01
Retailer/aggregator (VIC)	9.78
Retailer/aggregator (NSW)	8.68
Retailer/aggregator (SA)	8.13

Source: ACCC analysis

Table 2.5 below shows volume weighted average gas price estimates for 2018 based on long-term GSAs entered into since June 2017 in the Southern States.

Only one of these producer GSAs is oil-linked. As in the case for oil-linked Queensland GSAs, at the time prices were agreed, the parties would have held their own expectations about future movements of both oil prices and exchange rates and what this implied for domestic gas prices. This may not, however, reflect actual movements and current expectations about these variables for 2018.

Table 2.5: Volume weighted average 2018 wholesale gas prices in the Southern States (under GSAs executed since June 2017)

Type of supplier	Volume weighted average gas price ($/GJ)
Producer (VIC only)	9.74
Retailer/aggregator (VIC)	10.28
Retailer/aggregator (NSW)	10.11
Retailer/aggregator (SA)	9.13

Source: ACCC analysis

The ACCC emphasises that average prices for some locations are based on a small number of GSAs. Only three long-term producer GSAs were entered into for 2018 supply in the Southern States between July and November 2017, with all contracts being entered into with

Victorian producers. There were 12 C&I users who entered into long-term GSAs with retailers or aggregators over this period across the Southern States; however, in two states, only two GSAs were entered into with retailers or aggregators.

The Victorian producer GSAs that were executed over this period include those that were the result of the tender process run by the GBJV for gas supply in 2018. See box 2.1 for an explanation of the GBJV tender process, the outcome, and what the ACCC considers this process shows about the state of the gas market in the Southern States.

Box 2.1: GBJV's 2017 gas auction

Over the period May–July 2017, the GBJV used a blind tender process to sell gas. In contrast to the process of bilateral negotiations typically seen in the gas market, this process was uncommon in that it involved GBJV collecting price bids from interested gas buyers prior to selecting a shortlist for bilateral negotiations of GSAs.

In May 2017, GBJV commenced the tender process by contacting potential customers and inviting expressions of interest (EOI) to purchase gas for supply from 2018. For the purpose of submitting EOIs, bidders were provided with pro forma term sheets for a range of products, which specified key non-price terms. As a result of this, buyers' bids differed primarily on the price offered and quantity sought.

The EOI process received interest from a range of gas buyers, including C&I users, retailers, aggregators and GPGs. In total, GBJV received EOIs from 16 invitees, who collectively sought a total of up to about 80 PJ of gas for 2018. The GBJV had less than 20 PJ of gas available for sale for 2018. This is consistent with the ACCC's findings in the September 2017 report of an expected gas shortage in the Southern States in 2018.

There was a significant range in the bid prices, from about $7/GJ to over $11/GJ for a variety of products.

In July 2017, seven bidders were shortlisted by the GBJV, of which two were C&I users. The remaining bidders were notified that they were not successful.

Following negotiations with the shortlisted bidders over the next few months, the GBJV entered into GSAs with several of them for a total of 15 PJ of gas supply for 2018. All of the successful bidders were retailers and/or GPGs. The bulk of the quantity purchased by the retailers may be used to supply GPGs or the mass market, although some of it may be used to supply smaller C&I users.

The results of the tender appear to indicate that if the East Coast Gas Market is short on gas and different types of buyers are required to compete for gas supply, C&I users may be crowded out by other gas users, particularly GPGs. In the circumstances where GPGs are increasingly setting prices in the electricity markets, they are more likely to be able to pass on higher gas prices to their customers than C&I gas users, a number of which produce trade exposed products.

The average prices for retailer and aggregator GSAs in the Southern States shown in table 2.5 are all for supply to C&I users. These prices vary significantly across the market, ranging from $8.53/GJ (in South Australia) to $12.28/GJ (in Victoria).

Retailers and aggregators have also entered into long-term agreements with GPGs in the Southern States for 2018 supply since June 2017, with a volume weighted average price of $9.35/GJ.

As in the case of Queensland, the prices shown in table 2.5 should not be directly compared to the prices reported in the September 2017 report. Similar reasons as described above for Queensland prices also apply in this case. That is, the prices reported in September were estimated on the basis of different economic parameter assumptions for 2018, and they were based on GSAs executed in 2016 (before gas price offers peaked in early 2017).

However, these factors do not fully explain the differential between producer prices agreed in the Southern States in 2016 and those agreed recently. The increase in prices since that time may also reflect the tighter market conditions in the Southern States over 2017 relative to mid-late 2016 when the earlier prices were agreed and the expectation that southern

producers will offer gas prices that are shaped by LNG netback prices plus transportation costs. However, given the outcome of the GBJV's tender process (discussed in box 2.1) it may also be reflective of the potential higher willingness to pay of GPGs.

Since around July 2017, additional gas has been contracted by suppliers and around 12 large C&I users have entered into GSAs with retailers. The prices that have been agreed over this time are still much higher than historical levels and while C&I gas users in the Southern States are now more willing to enter into GSAs for supply in 2018, they still have serious concerns about the level of prices and the level of competition in the Southern States (as discussed in chapter 3).

Comparison of producer prices in the Southern States to estimated benchmark prices

As noted above, estimated benchmark prices in the Southern States for 2018, for gas produced in Victoria, range from $6.55/GJ to $9.93/GJ, depending on the buyer's location and the point in time the price was agreed or offered. All producer prices agreed in Victoria since June 2017 were either at the upper end of, or above, this estimated benchmark price range. However, these GSAs were all entered into around September 2017, when the ACCC's estimates of 2018 benchmark prices across the east coast market were lower. Therefore, at the time these prices were agreed, they were significantly higher than what the ACCC considered to be the range of appropriate benchmark prices in the Southern States for 2018 supply.

As noted above, the ACCC is currently exploring the reasons for differences in commodity gas charges between producers and retailers and will comment on this in a subsequent report.

3. C&I users: market experiences and supply by retailers

3.1. Key points

- Market conditions have improved since the September 2017 report, particularly for large commercial and industrial (C&I) users who consume more than one petajoule per year.
- Large C&I users have reported lower prices than early 2017 and more suppliers making offers, particularly Queensland suppliers.
- Most large C&I users the ACCC spoke with have now secured gas supply agreements (GSAs) for 2018 supply.
- Many C&I users have yet to secure supply for 2019 and are generally waiting to see if market conditions continue to improve before committing to new GSAs.
- Since the September 2017 report, we also spoke to a greater sample of smaller C&I users to find out more about their experience across 2017.
- For these smaller C&I users, while prices have fallen since mid-year, in some cases they are still getting offers from a limited pool of retailers and they are still being told that some retailers have no gas.
- Quantities of gas supplied by major retailers to C&I users appear to be declining significantly, and the ACCC will continue to engage with retailers and seek information to allow it to more effectively report on competition and pricing practices in retail markets.

3.2. C&I gas users have reported an improvement in the market

We detailed in our September 2017 report the experience of gas users in the East Coast Gas Market, including the effects of difficult market conditions on C&I users and gas powered generators (GPG) as users of gas. At that time, the ACCC identified there were offers to 23 C&I consumers that had not resulted in a GSA and over a third of the 18 C&I users the ACCC interviewed were considering either reducing production or closure due to high gas prices. For many of these users, gas is a feedstock to production or an essentially irreplaceable source of energy, and with the products they make often supplied on international markets, higher gas costs cannot be passed on.

Of the 23 C&I customers who we had identified were yet to enter into a GSA for 2018, our more recent information indicates that 19 have now settled contracts for gas supply in 2018.

We also contacted users we had spoken to for our September report for an update of their experience in the market. We spoke with ten of these users, focussing our consultation on those that had recently contracted or were still seeking 2018 or 2019 supply. A number of the users who did not provide additional information to the ACCC had earlier contracted for their 2018 supply and so there was no update to provide the ACCC. The ACCC also spoke with six users for the first time, including smaller users (less than 1 PJ per year) to get more of an understanding of the experience of smaller users in the market across 2017 in general.

Chapter 2 sets out the domestic price outlook for 2018 based on information provided to us by gas producers and retailers under our compulsory information gathering powers. The information we received voluntarily from gas users adds the user's perspective to this data.

Our discussions with gas users indicate that the size and location of users appear to have a material impact on the offers they receive. Large users are generally able to negotiate directly with gas producers at wholesale prices and they often have direct access to the larger transmission pipelines, giving them a wider range of competing suppliers and more competitively priced offers. On the other hand, smaller users generally source gas from the local distribution networks, which means that they will generally have only one or two

retailers offering supply and their quantities will generally not be attractive to producers to supply. They also will have to pay additional distribution charges.

One C&I user raised concerns with the ACCC over attempts to recontract supply for its plant with the sole supplier in the location, the North Queensland Energy JV, jointly owned by AGL Energy Ltd and North QLD Merchant Pty Ltd. Initially a contract for firm re-supply for the forthcoming period was not offered to the user, which may have resulted in the plant shutting down. After the ACCC made inquiries of the JV, an offer was made to the user.

While large C&I users have reported more suppliers willing to offer gas at lower prices, there is continuing concern about a lack of competition in the Southern States. Small industrial users have also seen price declines but some are still facing uncertainty.

3.2.1. Large industrial users have seen more suppliers willing to offer gas at lower prices

We spoke again with eight large C&I users that we had interviewed for our September report, as well as two new large users. These users generally had 2-3 competing suppliers making offers to them and two users (including one set out in case study 3.1, below) had offers from six different suppliers. These users generally had more suppliers willing to offer gas recently than there were in the first half of 2017. In particular, users have reported more engagement since September 2017 from the Queensland suppliers offering gas for 2018 and 2019. There is evidence of the producers proactively contacting potential customers and being willing to engage in further discussions, leading to better prices being offered, as would be expected in a well-functioning market.

Reported offers for large users in September/October 2017 were significantly lower than offers from earlier in 2017 of $10-16/GJ. Some large gas users thought that the ACCC's market monitoring and the government's focus on the export industry were likely contributors to the improved market conditions.

Users reported to the ACCC that, while prices offered have fallen, non-price terms and conditions offered by suppliers have generally remained unchanged over recent months.

In the 2017 September report, we reported that many users were delaying signing GSAs for supply for 2018 and beyond in the hope that government intervention and the ACCC's monitoring of the market would drive prices down.

Out of the eight large users we spoke with that had sought gas for 2018 or 2019 since mid-year, six users received offers from two or more suppliers. The two users that received offers from only one supplier had geographical or market constraints that significantly limited the ability of other suppliers to make genuine offers.

Most of these large users appear to have now secured GSAs for 2018 supply at gas prices around $9/GJ for 2018 (commodity only).

As at the end of November 2017, only one of these users was still uncontracted for 2018 and was in negotiations, while two had instead decided to use the spot market for their uncontracted load. Those entering (or considering entering) the short-term trading markets see these markets as a real alternative despite the price risk and additional prudential requirements, especially with the current low spot prices compared with GSA offers.

There are a greater number of users who have not yet secured gas supply for 2019. The ACCC observes that many of these users are waiting to see if market conditions continue to improve before committing to new supply agreements for 2019.

Case study 3.1–Large user in Southern States with multiple potential suppliers

An industrial user with a large, gas consuming plant in the Southern States went to market over September-October 2017 seeking gas supply offers for 2018. The user reported a lot more interest from suppliers compared to around the same time last year.

For the 2018 gas supply search, the user approached the market seeking a one-year GSA because it felt that prices were historically high and it did not want to lock in a fixed price for a long time. While there was a risk the prices could rise further, the user felt that prices were more likely to soften.

In this September-October period, the user was able to negotiate prices down through several rounds of a tender process that six suppliers participated in. This indicated to the user that there was genuine competition in the market that had not been present earlier this year.

The gas user advised that it was pleased that gas prices are lower than earlier this year, but considers that prices are still too high and are still more than double where they were a few years ago. The user considers that this makes it challenging, particularly in energy intensive trade exposed industries.

Of the GSAs entered into in the past three months, they were generally shorter-term GSAs between 1-2 years, compared with historic market GSAs of minimum five-year terms. Users were generally unwilling to commit to longer-term GSAs given the current uncertainty of market conditions.

While prices have dropped since earlier this year, for many industrial users the current prices are still too high to guarantee the long-term viability of their businesses.

Case study 3.2–Incitec Pivot Gibson Island fertiliser plant

Natural gas is one of the major inputs required for the production of ammonia and therefore is a critical feedstock for Incitec Pivot's nitrogen manufacturing operations. The manufacture of nitrogen-based products is energy intensive because it requires natural gas as both an energy source and a raw material.

Natural gas supply and price risk was highlighted as a key operational risk in Incitec Pivot's 2017 Annual Report.[38]

The Group has medium-term GSAs in place for its Australian manufacturing sites, with the exception of the Gibson Island fertiliser plant in Brisbane.

The current gas supply arrangements for Gibson Island will cease on 30 September 2018 and, while Incitec Pivot has explored numerous possibilities with a number of suppliers to secure an economically viable gas supply for the period beyond expiry of the current arrangements, to date it has been unsuccessful.

Incitec Pivot has also been pursuing discussions with all parties in the value chain to try to respond to increased gas costs at Gibson Island.

In consultations with the ACCC, Incitec Pivot has acknowledged increased engagement from LNG producers since June 2017, but considers that high pricing, significantly higher than current GSA prices and in excess of LNG netback price, remains a serious problem and has not changed to any great extent since its first approach to market.

Incitec Pivot reports in its 2017 Annual Report that it has explored numerous possibilities to secure an economically viable gas supply but to date has been unsuccessful. While it states that it is continuing to pursue a number of possible options, if no solution is found, it is likely that the facility will cease manufacturing operations.

[38] Incitec Pivot Limited, *2017 Annual Report*, IPL, 2017, http://investors.incitecpivot.com.au.

3.2.2. A limited number of suppliers in the Southern States remains a concern

Lack of gas supply and a limited number of suppliers in the Southern States appears to still be a significant concern for many users.

As discussed in Chapter 1, the Southern States are facing a significant decline in production, with no new sources of supply expected in 2018. While the LNG projects have offered significant quantities of gas to the domestic market, primarily to retailers, the LNG projects have made only a small percentage of offers to users in the Southern States.

One user is concerned about supply shortages in the South, with northern gas requiring significant additional transport costs to Victoria and Sydney. It considers that addressing moratoria and the GBJV marketing arrangements will improve competition. Another user is worried about gas supply security into the future and thinks that relying on gas from the north is not a viable long-term strategy.

The high cost and barriers to transport from Queensland is compounding the situation, while gas swaps seem to be an option for some (see more in Chapter 4 on transportation).

3.2.3. Small C&I users have been facing harsh market conditions

For this report, the ACCC spoke with a number of smaller C&I users who consume less than one petajoule per year. We spoke with users in both metropolitan and regional areas from a range of industries such as food production, mining and service industries to hear about their experiences throughout 2017, not just since the September 2017 report.

These businesses tend to contract with gas retailers rather than gas wholesalers/producers due to their smaller loads. While some have used a broker service to source gas supply offers, many deal directly with retailers and have typically remained with their incumbent gas supplier when it is time to renew their retail GSAs.

For the first half of 2017, these users faced market conditions similar to those reported for large users in the September 2017 report that were not reflective of a well-functioning market. Most small businesses we spoke with were only able to get genuine gas offers from one retailer. The ACCC observes that while users expected some price increases this year, they were shocked with prices double or triple their previous rates.

An example of the experience of one of the small C&I users that we spoke to is set out in case study 3.3 below.

Case study 3.3–Small user impact

A family-run commercial laundry in regional Australia shared its personal story with the ACCC. The business traditionally used around 15 000 GJ per year to run its boiler and had been buying gas from the same retailer for over a decade.

When the old GSA was nearing expiry in June 2017, the retailer offered a new GSA with a 130 per cent price increase and three days to sign. The buyer was shocked by the price increase and tried shopping around for competing offers. Most other retailers said they didn't have enough gas, and the one alternative retailer that may have had enough gas didn't have time to make a genuine offer before the buyer needed to re-contract.

The higher gas price would have made it uneconomic for the business to continue trading as it couldn't absorb cost increases or pass them on. The business would have had to close, which would have left over 30 local people out of work and would have resulted in the owners losing their family home.

For the business owners, the experience was extremely emotionally taxing and stressful.

Through the intervention of its local member of parliament, in September, the business was offered a

revised price $5/GJ lower than the June offer. It was also able to reduce its reliance on gas by substituting the majority of its gas for an alternative fuel. The lower gas price and fuel substitution meant that it was able to keep the business open.

Several of these smaller users rejected offers received earlier this year in the hope of securing better pricing, but were then offered prices around $2/GJ higher a short time later which they reluctantly accepted. Retail offers tend to have a seven-day validity, which did not give gas users enough time to test prices with other suppliers (if they were any).

The behaviour of retailers towards these smaller customers, who are often long-term customers seeking new contracts, is not what would be expected in a well-functioning market. This may be related to changes in retailer portfolio management strategies that may have limited the willingness or ability of some retailers to enter into new GSAs with C&I users, as discussed in section 3.3 below.

The users we spoke with had mostly recontracted prior to the Heads of Agreement at prices of about $13-14/GJ, with others having alternative plans in place to secure energy for the start of 2018. These plans included acquiring gas on short-term trading markets and acquiring gas as part of a buyers' group (see case study 3.4 below).

While many of these users typically prefer to lock in GSAs for longer periods to give them greater business certainty, we observe that most ended up with 1-2 year GSAs. For some, this was their choice as they wanted to see if market conditions would ease in future years. For others, they were only offered a short period.

For the users that contracted during mid-year price highs, some have had to make significant adjustments in reaction to higher gas costs, such as fuel switching and costly plant investments to reduce gas reliance, with others considering implementing similar strategies. However, limited flexibility in GSAs, like high take or pay rates, can mean that reduced gas use doesn't always result in reduced gas costs overall if achieved mid-contract. One user we spoke with has reduced its gas consumption through efficiency improvements to its production processes, but was still charged for unused gas due to contract restrictions.

In response to the high prices being offered to small users, one response has been for small users to join together to form a larger buying group, thereby opening up greater opportunities for supply. One experience is set out in case study 3.4, below.

Case study 3.4–Eastern Energy Buyers Group

On 22 November 2017, the ACCC issued a final determination granting authorisation to a new group of agribusinesses to jointly purchase energy in Victoria. The Eastern Energy Buyers Group (EEBG) can establish a joint energy purchasing group and run joint tender processes for electricity and gas for 11 years.[39]

The group's current members are industrial energy users who operate in the agriculture industry. Members have significant operations in Victoria and some operations interstate. The proposed joint tender process covers supply of electricity, gas and gas transport services to members of the group.

By combining their gas consumption needs, these businesses are likely to able to access wholesale arrangements with better prices than they would be able to achieve as smaller users.

One of the members of the group is Ridley Agriproducts, which has sites in Queensland, Victoria, NSW and SA.

Ridley believes that the gas prices offered to the buyers group in Victoria are up to 13% better than Ridley could have obtained on its own without the competition generated by the buyers group.

This is the second energy buying group the ACCC has authorised this year. In May 2017, the ACCC authorised the South Australian Chamber of Mines and Energy, along with 27 other South Australian

[39] ACCC, ACCC allows agribusinesses to jointly purchase energy, media release MR 216/17, 22 November 2017, www.accc.gov.au

businesses, to establish a joint electricity purchasing group.

3.2.4. Market conditions for smaller C&I users have improved somewhat in recent months

According to a consultant who sources energy for small C&I users, GSA offer prices have eased from around $18-19/GJ in mid-2017 to offers generally under $11/GJ in October/November. It reported that clients were also getting offers from at least two retailers. This suggests that retailers have additional gas supplies available to offer, which is to be expected since the LNG projects have offered significant quantities of gas to the domestic market, primarily to retailers, over the past several months.

Three small users we spoke with that have had interactions in the market since October had similar feedback. They all saw declines in price offers from the mid-year highs and most reported an increase in the number of retailers making offers. One of these users commented that more players in the market has led to better outcomes. The user said that the higher prices seen earlier this year would have led them to seriously contemplate closing part of their business, but the outlook is now more positive.

One business stated that it is still unable to bear current retail price offers, and has instead, since September 2017, chosen to source gas from the spot market through a third party broker. This particular approach is a recent development in the market, which has provided an additional option for smaller users. While this user has benefitted from lower spot prices in recent months, this approach does expose it to the risk of higher prices in the future, and participation requires coverage by a bank guarantee for three months' supply.

However, two users reported being told by some retailers that they still have no gas to offer. Some users are worried about a repeat of the experience of some users in late 2016, when industrial customers were turned away from contract renewals with existing retailers to find themselves in a position with an offer from a single retailer for a three-year minimum term.[40]

As discussed further in section 3.3 below, it appears that due to limited gas supply and higher gas prices, some retailers consider that they now face higher risks in supplying C&I users than they had in the past.

With small users being limited to a small pool of gas retailers (rather than being able to deal directly with gas wholesalers like their larger C&I counterparts), it is important to understand how retailers are approaching their interactions with this market segment.

Retail pricing to C&I users is complex, and there is further work required to understand how the retailers set prices for C&I users and the extent to which margins are applied.

3.3. Supply by retailers to C&I gas users

Following the publication of our September 2017 report, we have started to examine how retailers go about supplying gas to C&I users.

To inform this work, we have used our compulsory information gathering powers to obtain information from the major retailers (AGL, EnergyAustralia and Origin Energy) about:

- their overall quantities of gas supplied, or expected to be supplied, to C&I users over 2015–19
- their approach to the marketing of gas, and gas pricing strategies

[40] Angela Macdonald-Smith, 'Industrial energy users fear relief from gas deal only short-lived', Australian Financial Review, 7 Nov 2017, www.afr.com.

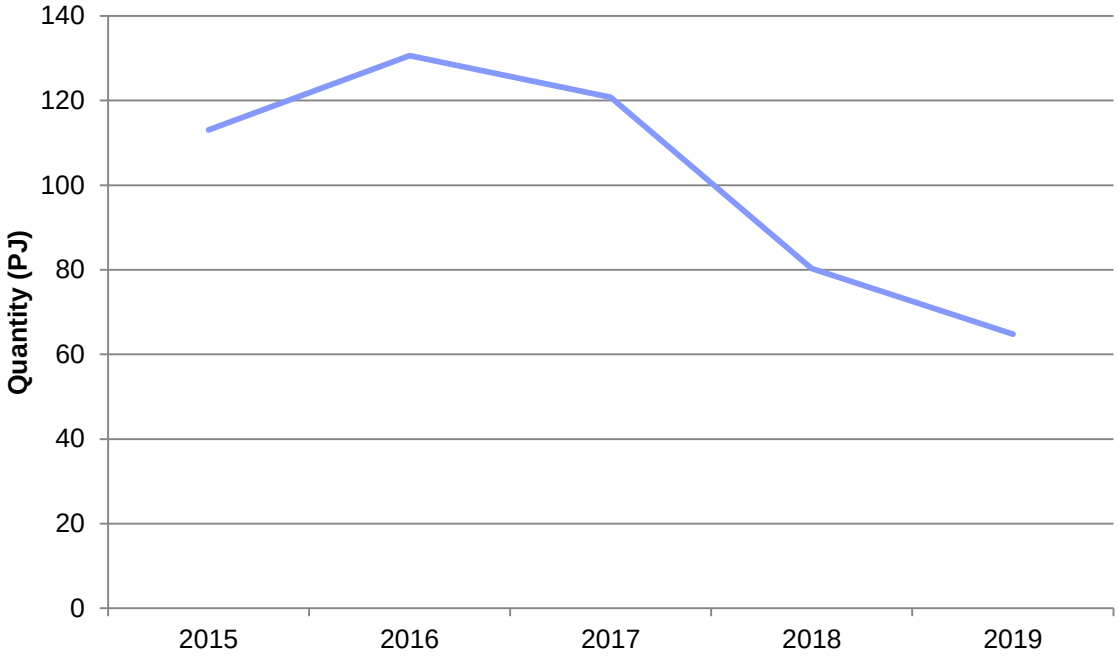
- the costs incurred in supplying gas to C&I users, such as the costs of goods sold (commodity costs, transportation costs, storage, AEMO market charges) and other operating costs
- how those costs are recovered from C&I users by reference to specific GSAs or offers made
- the margins payable by C&I users.

Our work in this area is ongoing; however, we have set out some preliminary observations below.

3.3.1. Quantities of gas supplied by retailers to C&I users

Chart 3.1 below shows the total quantity of gas that was supplied or is required to be supplied under a GSA (as at 18 October 2017) to C&I users by the major retailers over the period 2015 to 2019. Chart 3.1 shows a significant reduction in the quantities required to be supplied to C&I users in 2018 and 2019 compared with earlier years (a reduction of over 33 per cent is expected in the quantity to be supplied in 2018 compared with 2017). While some of this reduction, particularly for 2019, can likely be explained by C&I users having not yet entered into GSAs, this is unlikely to account for the entire decline.

Chart 3.1: Quantity of gas supplied, or contracted to be supplied as at 18 October 2017, by major retailers to C&I users



Source: ACCC data, as at 18 October 2017

As set out in the September 2017 report, supplier comments in internal board documents suggested that a number of retailers were declining to supply C&I users due to lack of portfolio supply, and there was a view that one major retailer was focussing on gas retail only for 2018 and 2019.[41]

The ACCC sought information from the major retailers about the reasons for the decline in the quantity supplied to C&I users (shown in chart 3.1). Responses from the retailers appear to indicate that due to limited gas supply and higher gas prices, some retailers consider that they now face higher risks in supplying C&I users than they had in the past. In particular, some retailers are concerned that if they purchase large quantities of gas before signing up customers, they may not be able to sell the entire quantity of gas under long-term GSAs and would have to sell it at lower prices on the domestic spot markets instead. Some retailers are also concerned that, at current gas prices, C&I users are at higher risk of market exit, which could again put the retailer into a position of having to sell undelivered quantities of gas into the domestic spot markets.

As a result, we observe that some retailers have changed their strategies for managing their gas portfolios. For example, some retailers only purchase gas to supply C&I users once the user has committed to purchase gas from the retailer, rather than securing supplies in advance. Others have chosen to enter into GSAs only with re-contracting C&I users at various periods. This has limited the willingness or ability of some retailers to enter into new GSAs with C&I users.

When faced with the higher prices of new offers, C&I users (both new and existing) have responded in a range of ways, such as:

- modifications to operations to reduce gas requirements
- sourcing gas through the AEMO-operated wholesale markets

[41] ACCC, Gas Inquiry 2017-2020, September 2017, p. 46.

- looking to other suppliers to meet their gas requirements, such as smaller retailers and producers.

We understand Alinta Energy has recently decided to become a supplier to C&I gas users in Victoria, New South Wales and South Australia. Alinta has secured additional gas supply from producers for this purpose. While the total quantities at this stage are under 10 PJ, Alinta continues to engage with potential new customers.

Also, we are aware of at least one new retailer that offers gas supply at prices based on the relevant AEMO-operated wholesale gas market, determined by the location of the C&I user. Users in Sydney, Adelaide, or Brisbane may be able to utilise the Short Term Trading Market (STTM) and users in Victoria may be able to utilise the Declared Wholesale Gas Market (DWGM). This allows users, who might have previously been too small to justify registering and participating in the wholesale gas market, to use the markets to source their gas requirements.

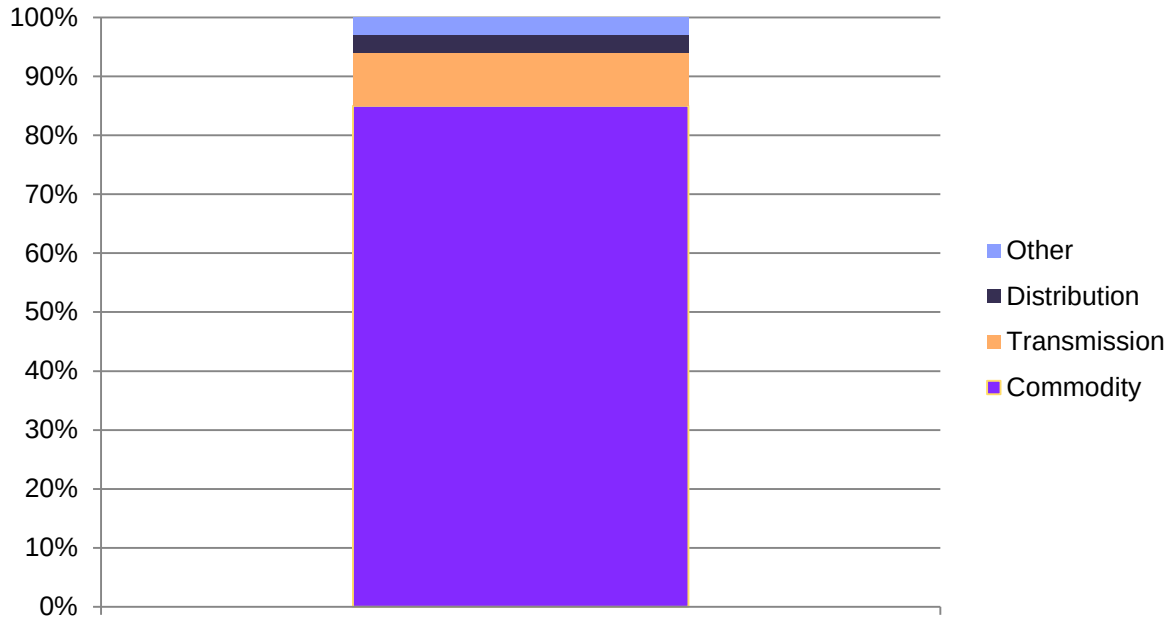
Recent prices in both the STTMs and Victoria's DWGM have generally been lower than the prices offered to C&I users from both retailers and producers (as discussed in section 2.2). Given this, it is understandable why some users have decided to rely on these markets more to source their gas requirements. We note, however, that this strategy is not risk free. Spot prices fluctuate depending on the supply and demand conditions at a given point in time. Users could find themselves facing higher costs in the event of an adverse move in spot prices.

3.3.2. Components of delivered gas prices charged by retailers to C&I users

The ACCC obtained information from the major retailers on the components of delivered gas prices they charge to C&I users. This includes the gas commodity component and other categories of costs the retailers incur, or expect to incur, in supplying gas to C&I users. Retailers also provided breakdowns, based on those components, of a number of individual GSAs and offers made to C&I users.

Based on this information, chart 3.2 shows indicative proportions of the various components of prices charged by retailers to C&I users. In chart 3.2, the gas commodity component represents 85 per cent of the total, transmission costs represent 9 per cent, distribution costs 3 per cent and other costs also 3 per cent. The ACCC notes that this chart is for illustrative purposes only. It is not specific to a particular retailer and does not represent any individual transaction.

Chart 3.2: Indicative components of a C&I user's retail gas bill



Source: ACCC data

The gas commodity component appears to generally make up around 80–90 per cent of a retail price to C&I users. In quoting an individual C&I user, a retailer may base the gas commodity component on its view of the wholesale price of gas over the expected period of supply, which may be different to the actual costs incurred by the retailer in purchasing the gas. The approach may differ for larger users who are able to participate directly in AEMO-operated wholesale markets and/or have their own transportation arrangements.

The second largest contributor is transmission costs. Transmission costs can vary depending on the location of the gas user relative to the gas supply source. They can be charged based on consumption ($/GJ) but we have observed some instances of fixed charges. Despite this, and after taking into account the gas consumption where fixed charges were applied, from the information considered to date, transmission costs tend to sit at around $1.00–1.20/GJ. We have also observed:

- for C&I users in, or near, the Victorian transmission system, being supplied by a local gas source, transmission costs tend to be lower than C&I users in other States (around $0.35/GJ) and are often passed through by the retailer 'at cost'
- for C&I users in other States, transmission costs tend to be higher–this is likely related to the additional costs of transporting gas on more than one pipeline (we observed costs at around $1.00–1.20/GJ but in some cases approaching $3.00/GJ)
- retailers appear to differ in their treatment of transmission costs outside of Victoria–on some occasions, a margin on top of charges by transmission pipeline owners is applied.

Distribution costs appear to be passed through by the retailers 'at cost'.

The other costs reported by the retailers vary and include costs relating to storage, market charges (relating to AEMO-operated wholesale markets) and jurisdiction specific costs such as the Victorian Energy Efficiency Target scheme.

Retail pricing to C&I users is complex, and limited information was provided to the ACCC in time for its inclusion in this report. There is further work required to understand how the

retailers set prices for C&I users and the extent to which margins are applied. The ACCC will continue to engage with retailers and seek information to allow it to report further on competition and pricing practices in retail markets.

4. Transportation and storage

4.1. Key points

- There is insufficient gas in the south to meet domestic demand and so gas from Queensland must flow south to meet that demand. Therefore access to transport, particularly on the key north to south transport routes, is becoming increasingly important to market participants.
- At present, most of the key pipelines (South West Queensland Pipeline, Moomba to Adelaide Pipeline System and Moomba to Sydney Pipeline) necessary to deliver gas from Queensland to the Southern States are close to fully contracted in 2018. Congestion will limit the benefits of extra gas being made available to the domestic market and will limit the competitive outcomes in the Southern States.
- Access to pipeline capacity appears to be a barrier to entry for producers in Queensland seeking to supply gas into the Southern States. If spare contracted but un-nominated pipeline capacity was being released in the market by either service providers or primary capacity holders, this could improve the level of supply and increase competition in the Southern States.
- Retailers have contracted a significant proportion of the firm transportation capacity on these key pipelines, but there is no clear evidence to suggest retailers are purposely withholding or 'hoarding' capacity.
- Secondary trading on key pipelines required to deliver gas south could help move more gas south, but trading activity by retailers using these pipelines has been low in recent years.
- When capacity trading reforms become operational, they should facilitate a greater level of secondary capacity trading and help shippers gain access to contractually congested pipelines, increasing efficient use of pipelines and allowing gas to move where it is most needed. Until these reforms take effect, the ACCC will continue to monitor pipeline usage and capacity trading.
- Some market participants have also entered into gas swap arrangements to overcome pipeline congestion on the key north to south transport routes and are paying fees that are lower than transportation costs. While gas swaps can avoid congestion problems and lower 'transport' costs, there are limits on how much gas can be swapped between locations. One market participant currently views swaps as only a short-term solution.
- Most of the forward haul pipeline tariffs paid in July 2017 have increased in line with inflation since 2015, which is not surprising given most prices are payable under contracts that were entered into prior to 2015. The ACCC expects to see downward changes in prices, particularly given the introduction of the information disclosure and arbitration regime under Part 23 of the National Gas Rules. The first arbitration under this Part was notified to the Australian Energy Regulator in late November by Hydro Tasmania for services on the Tasmanian Gas Pipeline.
- Gas storage is becoming an increasingly important source of seasonal supply, particularly in the Southern States where major gas producers are no longer offering 'swing' services. Storage could facilitate more efficient usage of pipeline capacity and availability and access to storage could become even more important if it is needed to store Queensland gas purchased and transported in periods of low demand for use in the Southern States in periods of high demand (usually, winter).

4.2. Overview

Gas transmission pipelines transport gas at high pressure from production fields to major demand centres in cities and regional areas. They are a key component in the gas supply chain. The East Coast Gas Market has undergone significant transition in recent years. Previously, delivery of gas was point to point (from supply area to demand centre). Now the East Coast Gas Market has become an interconnected network of pipelines where gas is shipped in all directions and across multiple pipelines to where it is needed most.

There are currently three forms of pipeline regulation: full regulation, light regulation and Part 23 of the National Gas Rules (NGR) which applies to non-scheme pipelines. A brief description of each form of regulation is summarised in Appendix A of this report.

The ACCC's 2015 inquiry found that while pipeline operators were responding well to market needs in terms of investment, there was evidence of monopoly pricing giving rise to higher prices and economic inefficiencies.[42] In the September 2017 report, the ACCC reported that gas transportation costs, availability of pipeline capacity and lack of transparency were cited by gas users and GPG as barriers to efficient market competition for gas supplies.[43]

Given the ACCC's finding of a shortfall of gas in the Southern States in the September 2017 report, access to transportation capacity on reasonable terms (including prices) in facilitating the supply of gas from Queensland to the Southern States is critically important. The ACCC's immediate focus has been on this particular part of the pipeline network which includes the South West Queensland Pipeline (SWQP), the Moomba to Sydney Pipeline (MSP) and the Moomba to Adelaide Pipeline System (MAPS).

The ACCC will be undertaking a more extensive analysis of transportation issues and will broaden our scope to focus on other major pipelines in the east coast in a future report of this Inquiry.

4.3. Key pipelines to the Southern States are contractually congested in 2018 and 2019

Outside Victoria, gas transportation in the East Coast Gas Market is currently dominated by long-term bilateral agreements between service providers and shippers. The firm forward haul service is generally the most common service sought by customers as it has the highest priority of any transportation service.

Where pipelines are contractually congested potential shippers seeking firm transportation services on that pipeline would need to seek alternative options as discussed below.

The SWQP along with the MSP and MAPS are the key transport routes to move gas from Queensland to the Southern States. As shown in table 4.1 below, the primary capacity holders on these pipelines are retailers, large C&I users, GPG and gas producers.

Table 4.1: Gas Bulletin Board Shipper List[44]

SWQP	MAPS	MSP
Santos	EnergyAustralia	EnergyAustralia

[42] ACCC, *Inquiry into the east coast gas market*, April 2016, pp.8-9.

[43] ACCC, *Gas Inquiry 2017-2020, Interim Report*, September 2017, p.58.

[44] Gas Bulletin Board, *BB Shippers with Contracted Pipeline Capacity, BB Shipper List – Moomba to Adelaide Pipeline System – 6 October 2016 ; Moomba to Sydney Pipeline – July 2017; South West Queensland Pipeline – July 2017,* accessed 4 December 2017.

Origin Energy Retail	Santos Direct	Visy Paper
AGL Wholesale	Origin Energy Retail	Santos Direct
GLNG Operations	AGL Wholesale	Origin Energy Retail
Braemar Power	Adelaide Brighton Cement	Origin Energy Uranquinty Power
Incitec Pivot	OneSteel Manufacturing	AGL Wholesale
	Heathgate Resources	Origin Energy LPG
	Pelican Point Power Limited	Covau
		Braemar Power Project
		ERM Power
		Qenos
		Tarac Technologies
		Weston Energy

Table 4.2 below sets out the uncontracted capacity information outlook for the three pipelines as reported on the Natural Gas Services Bulletin Board (GBB).[45] As table 4.2 below shows, for the period December 2017 to October 2018:[46]

- SWQP has very limited uncontracted firm forward haul capacity available to transport gas from Wallumbilla to Moomba.
- There is firm forward haul capacity available on the MSP to transport gas between Moomba and NSW and potentially into Victoria (using the Vic-NSW Interconnect). However, constraints on the SWQP limit the value of this available capacity.
- MAPS is fully contracted making delivery of gas into Adelaide from Queensland challenging.

45 Gas Bulletin Board, Uncontracted Capacity Outlook (INT 929), accessed 14 November 2017. All percentage values shown in the table reflect an average of the terajoules per day (TJ/d) for each outlook month.

46 Gas Bulletin Board, Uncontracted Capacity Outlook *(INT 929)*, accessed 14 November 2017

Table 4.2: Uncontracted capacity information–reported as at 7 December 2017

	SWQP (westerly direction)[47]	MSP (southern direction)[48]	MAPS (southern direction)[49]
01/2018	1.5%	15%	0%
02/2018	1.5%	15%	0%
03/2018	1.5%	15%	0%
04/2018	0%	1.4%	0%
05/2018	0%	0%	0%
06/2018	0%	0%	0%
07/2018	0%	0%	0%
08/2018	0%	0%	0%
09/2018	0%	13%	0%
10/2018	1.5%	33%	0%
11/2018	1.5%	33%	0%
12/2018	1.5%	33%	0%

Source: Natural Gas Bulletin Board, Uncontracted Capacity Outlook, accessed 7 December 2017

There appears to be limited uncontracted capacity based on Gas Bulletin Board information over 2018. However, in reviewing pipeline capacity information provided by the operators in September 2017, we note that there may be further uncontracted capacity on some of the key pipelines from late 2018. However, capacity constraints could materialise if circumstances change. We will be monitoring pipeline capacity information in this inquiry.

4.3.1. Gas flows on the SWQP

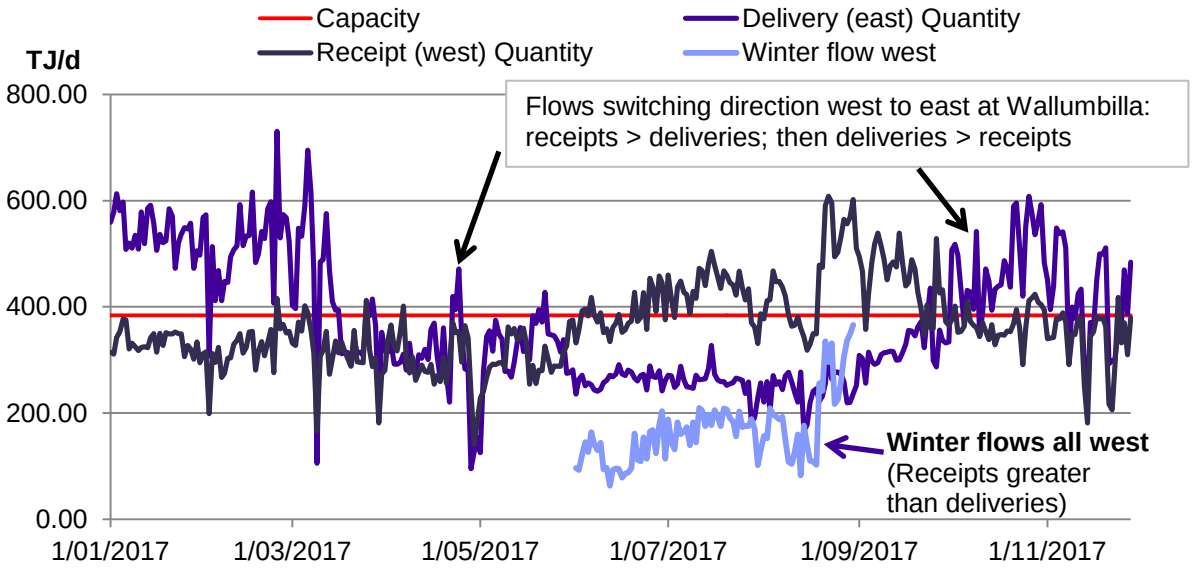
The chart below shows deliveries and receipts (on a combined shipper basis) as reported on the Gas Bulletin Board for the SWQP (Wallumbilla zone) from 1 January to 28 November 2017. It also shows the stated nameplate capacity of the SWQP (west).

[47] Gas Bulletin Board, SWQP nameplate capacity: 384 TJ/d

[48] Gas Bulletin Board, MSP nameplate capacity: 439 TJ/d

[49] Gas Bulletin Board, MAPS nameplate capacity: 237 TJ/d

Chart 4.3– Flows on the SWQP (Wallumbilla zone) 2017



Source: AEMO, Natural Gas Services Bulletin Board, Actual Flow, SWQP, Wallumbilla, 1 January to 28 November 2017

This chart shows higher receipts into the SWQP from Wallumbilla (gas moving west on to the pipeline) over winter 2017. Since winter has ended, it shows more gas being delivered into Wallumbilla from off the SWQP (gas moving east). This pattern of receipts and deliveries is consistent with contracts the ACCC identified whereby additional quantities of gas were contracted for delivery west this winter towards southern markets.

The ACCC sought further detailed information from APA and shippers to understand individual shipper deliveries and receipts given industry concerns over whether capacity on the SWQP west to deliver gas to southern markets was being utilised. The ACCC found from the individual data that:

- Key shippers with firm western-haul capacity on the SWQP were nominating at or near their firm capacity limits over the 2017 winter period, and in some cases above that capacity, given rights to also nominate as-available services and/or overruns.
- Notwithstanding the above findings, there is some unutilised capacity in non-peak periods that could be made available through secondary trading. For example, in transporting gas in a westerly direction on the SWQP during the period March to May 2017, there was around 46 days where a retailer had allocated only 50 per cent or less of its firm contracted capacity. In that same period, there were also many days where another retailer had 25 per cent or more unutilised western-haul capacity..

To overcome pipeline capacity constraints, shippers seeking to transport gas from Queensland to the Southern States who do not hold firm capacity could:

- negotiate with an existing capacity holder for secondary capacity. A shipper seeking access could seek unutilised capacity from primary capacity holders on an ongoing basis or through short-term trades. This is discussed in section 4.4.1 below.
- acquire capacity from pipeline operators through as-available or interruptible services, or, where available, the pipeline operator's capacity trading sites. The pricing of these services is considerably higher than firm forward haul services. This is discussed in section 4.4.3.1 below.
- Enter into gas swap arrangements. This is discussed in section 4.4.3.2 below.

A further way to overcome capacity constraints is for shippers to seek pipeline capacity expansions. The ACCC has seen evidence of a pipeline operator engaging with shippers in discussing options to increase physical pipeline capacity to meet demands. However, this requires additional capital investment which may not be open to smaller market participants. Smaller participants may not have certainty of demand to be able to take on the financial risks of underwriting the investment and contracting under long-term foundation contracts. Further, even if capacity expansion agreements have been executed, they are unlikely to have an immediate impact in alleviating the capacity constraints on the key pipelines for 2018 because any expansion will not be completed by 2018.

4.4. Retailers are using their capacity but industry is yet to realise the benefits of secondary trading

The major retailers play an important role in facilitating the supply of gas to the Southern States. As identified in Table 4.1 above, two of the three major retailers hold firm capacity on all three of the key pipelines[50] and those retailers have contracted a significant proportion of the firm transportation capacity on the key pipelines necessary to deliver gas to the Southern markets.

To date the ACCC has not found evidence of systemic withholding of capacity by the retailers on the key pipelines to transport gas from Queensland to the Southern States. Our examination of pipeline usage levels on the SWQP, MSP and MAPS shows that retailers are using their capacity, and at certain periods of the year where demand is high (i.e. winter), they are using their capacity at close to or above their contracted firm capacity.

In the past, firm pipeline capacity was typically sold based on a flat demand profile and generally not exposed to season variability. This may have resulted in unutilised contracted capacity and therefore inefficiencies in the use of pipelines. However, some retailer portfolios are becoming increasingly ‘shaped’ where there is more variation on contracted capacity quantities throughout the year rather than a flat contracted Maximum Daily Quantity (MDQ) all year round. This means there is less idle firm capacity when there is lower demand. Notwithstanding the above findings, there is some unutilised capacity in non-peak periods that could be made available.

4.4.1. Secondary capacity trading activity on the key pipelines between shippers is low

Primary capacity holders that have unutilised capacity can sell their capacity through long-term and short-term trades. The ACCC’s 2015 inquiry found that some secondary trading was occurring across the entire east coast (predominantly in Queensland and South Australia) but short-term trades were less widespread. There was also no evidence of systemic withholding of capacity on major transmission pipelines.

Secondary trading activity by retailers on the key pipelines linking Queensland and the Southern States has been very low in recent years. Based on information provided to the ACCC under compulsory information notices, on the key pipelines:

- Only one retailer has entered into long-term secondary trading agreements, with most of the agreements entered into before 2015.
- One retailer has not made any offers for capacity trading services nor have they received any requests for this service during 2017.
- One retailer has received two requests for pipeline capacity in 2017. Negotiations are ongoing.

[50] GBB, *BB Shipper List – Moomba to Adelaide Pipeline System – 6 October 2016 ; Moomba to Sydney Pipeline – July 2017; South West Queensland Pipeline – July 2017,* accessed 14 November 2017

- The retailers have not entered into any new secondary trading agreements for 2018 and 2019.

In terms of secondary trades on the SWQP from Wallumbilla to Moomba, there are currently no capacity listings on the Gas Supply Hub's listing service, as at 17 November 2017[51] and no trades have been entered into using APA's secondary pipeline capacity trading platform for SWQP (westerly direction) in the period 1 January 2017 to November 2017.[52]

It is not clear at this stage why more secondary trading on this key pipeline is not occurring, given primary capacity holders still pay for unutilised capacity and could recoup some of their costs through on-selling to a secondary shipper. Potential reasons are:

- shippers may not have a strong incentive to sell spare capacity because the cost and effort of doing so, and the risk of being short capacity if the sale occurs a long time before the nomination cut-off time, may exceed the revenue generated
- the service provider, as the only seller of day-ahead capacity after nomination cut-off time, has the ability and incentive to price contracted but un-nominated capacity above the levels that would be expected in a workably competitive market, and
- the market for contracted but un-nominated capacity is complex and subject to co-ordination failure, because multiple buyers need to transact with multiple sellers to reach the welfare-maximising allocation and the only way this can currently occur is through bilateral negotiations, which can be lengthy, complex and expensive.[53]

One shipper told the ACCC that the pricing of secondary capacity has been an ongoing issue and that retailers do not have an incentive to release spare capacity to a direct competitor. This shipper has instead entered into swap arrangements as a short-term alternative in flowing gas to the Southern States.

4.4.2. Unlocking pipeline capacity may increase the level of competition for gas supply in the Southern States

As discussed in Section 1.5, the Southern States are forecast to produce insufficient gas to meet demand in those States. The ACCC considers the lack of access to transportation, particularly on the key north to south transport routes, is a barrier to entry into the Southern States, contributing to the lack of gas supply and diversity of gas suppliers in the Southern States.

One shipper told the ACCC that its inability to obtain firm transportation rights on reasonable prices has been a barrier challenging it from entering the Southern market to supply gas directly to users. Without access to transport on the key north to south routes, the shipper has considered selling its own gas to existing capacity holders and therefore foregoing the opportunity to compete in the Southern States. This transaction would involve a transfer of margin to the retailer and due to market concentration in the Southern States, potentially greater rents than if the shipper had entered into the market and competed with existing market participants.

The ACCC considers that spare pipeline capacity should be released to make it easier for market participants, particularly new entrants, wanting to transport gas to the Southern States. This could increase the level of supply and diversity of suppliers in the Southern States and may put downward pressures on gas prices. It would also encourage more efficient use of existing infrastructure and pipeline services.

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51 GBB, *Capacity Listing,* accessed 17 November 2017. Access here: http://www.gasbb.com.au/Capacity%20Listing.aspx

52 APA, *Capacity Trading, Trading Summary Information, 1 January 2017 to 30 November 2017*, accessed 30 November 2017. Access here: http://capacitytrading.apa.com.au/capacitytrading.aspx

53 AEMC, *Stage 2 Final Report: East Coast Review*, 23 May 2016, pp. 72-73.

The ACCC considers that the capacity trading package, which is currently being developed and provides for the introduction of a capacity trading platform and day-ahead auction, will facilitate a greater level of secondary capacity trading and should help shippers gain access to contractually congested pipelines.[54] The new reporting framework for secondary capacity trades should also reduce information asymmetries between shippers and primary capacity holders, and provide a clearer signal of the market value of capacity. The ACCC understands that these reforms are not expected to be implemented until 1 March 2019, so it will be some time before they can play a role in facilitating the release of capacity on key pipelines. The ACCC will continue to monitor the behaviour of pipeline operators in relation to pipelines and the behaviour of primary capacity holders in respect of the release of contracted but un-nominated capacity on the key pipelines.

ACCC investigation into secondary capacity on regional pipelines

The ACCC has investigated allegations that gas retailers who control all, or a significant proportion, of the capacity of a pipeline were not making unused capacity available to other gas retailers. The alleged conduct raised concerns regarding the restriction of competition for the supply of gas on those pipelines.

Following the ACCC's investigation, we have seen instances of gas retailers making pipeline capacity available for use by other gas retailers in regional areas. These instances have resulted in more competitive outcomes by giving gas users a choice in their preferred gas supplier.

In the ACCC's view, there is no reason why similar releases of capacity should not occur on the major transmission pipelines in the east coast, including on the key pipelines linking Queensland and the Southern States.

We will continue to monitor and report on pipeline usage and whether parties are making spare capacity available. We will seek quick enforcement outcomes if a failure to make pipeline capacity available is likely to contravene Part IV of the CCA.

4.4.3. Other alternatives to firm transportation to the South may not be complete solutions

4.4.3.1. As available and interruptible services

As mentioned in section 4.3.1 above, shippers can acquire contracted but un-nominated capacity from pipeline operators through as-available or interruptible[55] services when pipelines are fully contracted.

In the ACCC's 2015 inquiry, the ACCC found that some pipeline operators were charging excessive prices for access to these services.[56]

We have reviewed all GTAs currently on foot that have interruptible rights on the SWQP and it appears that shippers would be charged interruptible rates that are 1.2 to 1.9 times the firm transportation rates for interruptible services from Wallumbilla to Moomba. The ACCC considers the pricing to be high and the level of pricing suggests that the pipeline is unlikely to be constrained by competition from shippers offering a similar service through secondary capacity trading. These prices may be making delivered gas uncompetitive and may be inhibiting market entry that would be economically efficient and improve overall economic outcomes.

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54 GRMG, *Standardisation Related Reforms and the Capacity Trading Platform* and *Day-Ahead Auction of Contracted but Un-Nominated capacity and Reporting Framework Consultations*.

55 As available service is 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. Interruptible service is 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.

56 ACCC, *Inquiry into the east coast gas market*, April 2016, p.142.

The ACCC will look at the extent to which shippers are utilising these services and whether the high prices charged by pipeline operators mean as available and interruptible services are not a viable long-term solution for shippers in overcoming pipeline capacity constraints in a future report of this Inquiry. The ACCC will also broaden the scope of its analysis to review as available and interruptible service pricing on the major transmission pipelines in the east coast market.

4.4.3.2. Locational gas swap arrangements

Gas swap arrangements[57] are another option that have been used by market participants to overcome pipeline capacity constraints and can facilitate greater competition in gas supply in the Southern States. In terms of arrangements made specifically to transport gas down to the Southern States:

- Santos recently entered into a swap arrangement with APLNG to swap up to 300 PJ of uncontracted gas in eastern Queensland to reduce transport costs.[58]
- Two market participants entered into an arrangement to swap gas between Moomba and Mt Larcom (near Gladstone) in 2017. The swap fee is around $0.70/GJ. This is around 20 per cent cheaper than paying for transportation costs in 2017 on the SWQP to transport gas to Moomba. A discussion on pipeline pricing is found below at section 4.5.
- Two market participants entered into an arrangement to swap gas between Wallumbilla and a number of delivery points in the Southern States for three years commencing in 2018. The fee payable depends on which delivery points are used. However, in any scenario the swap fee is less than the cost of physical transport.

Gas swap arrangements show some promising signs of providing flexibility to market participants by allowing them to overcome capacity constraints and reduce transportation costs (and potentially, therefore, delivered gas prices). However, it is too early to assess the effects that gas swap arrangements may have on alleviating pipeline capacity constraints. We note that these deals can be complicated and take a long time to negotiate. Additionally, the quantity of gas available to be swapped is limited to the quantity of gas that would otherwise have been transported between the locations on pipelines.

One shipper told the ACCC that swap arrangements are useful on a short-term basis; however, a downside is that these arrangements reveal their commercial positions to the swap party. This could limit the willingness of shippers to seek swaps with their direct competitors in gas supply markets. The shipper currently views swaps as only a short-term solution. The ACCC will continue to monitor and investigate the level of swap arrangements taking place across the east coast market and will report on gas swap arrangements in subsequent reports. We will also seek to determine what, if any, impact gas swaps are having on pipeline service pricing.

4.5. Gas transportation pricing may not come down substantially until current contracts roll over and new contracts are signed

The ACCC's 2015 inquiry found evidence of a large number of existing pipelines engaging in monopoly pricing and that this was giving rise to higher delivered gas prices for users and, in

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[57] 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.

[58] Australian Financial Review, *Santos 'evacuates' new Queensland gas to ease gas drought down south*, 9 November 2017. Access here: http://www.afr.com/business/santos-finds-a-magic-pudding-to-swap-20171109-gzi3x3?login_token=1eht3Sx0-D3Il0UffcRpdu7ff9_8tSL07QYtvbKs8zCmDcA_InpFzKLdH2BrnVfYeZOyGEY4iEfxodD_KYPFBQ&expiry=1511151814&single_use_token=FZUuUOlvlnvCFGEM4sQxl244pgAdT7uD4kq778CKNDNzhkaZ2PcbKRRB1-SkHBMK9ow9YSYgzROMJ5aSrxRFqg

some cases, lower ex-plant prices for producers.[59] The ACCC also found that this was having an adverse effect on the economic efficiency of the east coast gas market and upstream and downstream markets.

In 2017, high gas transportation costs continue to be cited as an issue that is giving rise to higher delivered gas prices.

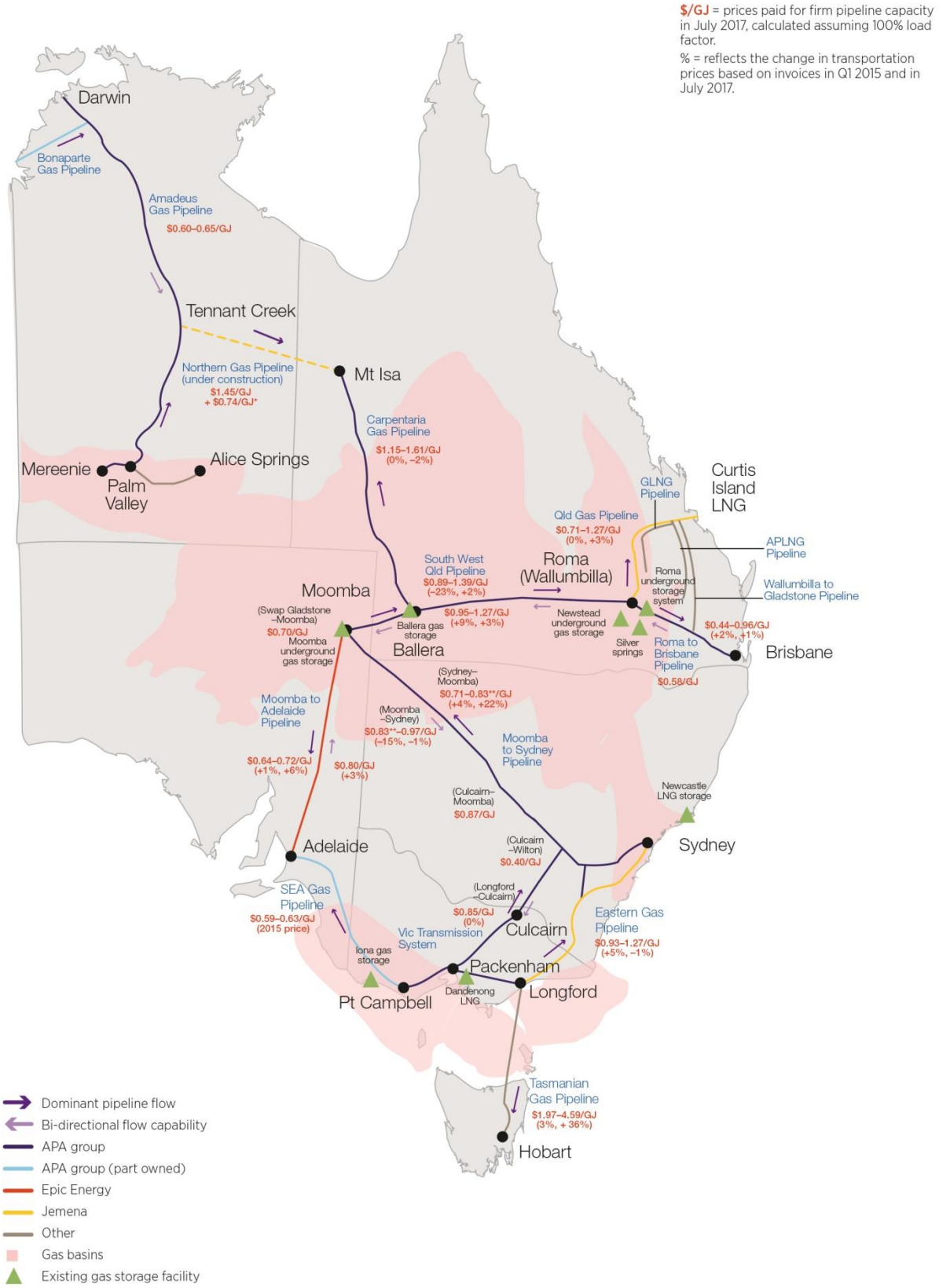
The pipeline network map below shows the volume weighted average price that shippers paid to major pipeline operators in July 2017 for firm forward haul services.

The average prices have been calculated using prices specified in invoices issued by pipeline operators under gas transportation agreements (GTAs) entered into for a term of one month or longer.

The ACCC has compared the prices paid in Q1 2015 as reported by the ACCC in its 2015 inquiry. As shown in the map below, firm forward prices paid in 2017 have largely increased in line with inflation. The minimal changes in prices since 2015 is not surprising given that more than 80% of the GTAs that are reflected in the July 2017 invoices were entered into prior to ACCC's 2015 inquiry.

[59] ACCC, *Inquiry into the east coast gas market*, April 2016, p.92.

Figure 4.1– East Coast pipeline network and storage



Notes: The transportation prices are based on invoices in July 2017 provided by pipeline operators, and exclude GST.
Actual prices in GTAs vary due to differences in key commercial terms, including load factor, capacity commitments, contract length, the time at which the prices were agreed or reviewed. They may also vary if the GTA provides for services across a number of pipelines.

* Tariff based on published tariff appearing on Jemena's website. $0.74/GJ reflects the nitrogen removal service.

** The price of $0.83/GJ on Moomba to Sydney and Sydney to Moomba includes the cost of compression at Moomba.

In relation to more significant prices changes, the ACCC notes that the:

- 36 per cent increase on the Tasmanian Gas Pipeline is due to an increase in price for one shipper, which was agreed in 2014.
- 15 per cent decrease on the Moomba to Sydney route is due to a decrease in tariff paid for by one shipper compared with what it was paying in 2015.
- 22 per cent increase on the Sydney to Moomba route reflects the inclusion of a tariff paid by one shipper who did not have this service in 2015.

The ACCC is aware of current negotiations for pipeline access and has seen new pipeline agreements that have been executed for 2018 and 2019. One shipper currently in negotiations with a pipeline operator for transportation access for 2018-19 told the ACCC that while it has seen more flexibility from the pipeline operator, the level of pricing continues to be a concern.

We support the information disclosure and arbitration regime under Part 23 of the National Gas Rules and expect this will improve the bargaining positions of shippers and see downward changes in prices. The first arbitration under this Part was notified to the Australian Energy Regulator in late November by Hydro Tasmania for services on the Tasmanian Gas Pipeline.

The ACCC will be focusing on the newer agreements in an upcoming report and will provide a more comprehensive analysis on transportation pricing.

4.6. Gas storage

To meet seasonal peak demand in South Eastern Australia and manage market risks, retailers are contracting an increasingly diverse range of pipeline storage services. At the same time the Iona underground gas storage facility is expanding its capabilities to deliver gas over the Southern peak demand period.

The costs and benefits of further underground storage to meet seasonal demand fluctuations can be difficult to predict as in part it depends on commodity gas price variability across the year and whether storage will lead to overall cost savings.

Gas storage also continues to play an important role in the East Coast Gas Market in managing supply outages and maintaining system security.

4.6.1. Overview of Storage

There are three types of storage available in the East Coast Gas Market:

- large longer-term storage facilities located close to gas fields in Queensland, Victoria and South Australia, using depleted gas fields
- small seasonal or peaking storage facilities (including the Dandenong LNG storage facility) located close to gas demand centres in Victoria and New South Wales
- short-term peaking storage services on gas pipelines using pipeline park and loan services

Table 4.3 - Operating Storage Facilities (excludes pipeline storage)[60]

Storage facilities	Operator	Storage Capacity (PJ)
Moomba (South Australia)	Santos (no third party access)	70
Roma (Queensland)	GLNG (no third party access)	50+*
Silver Springs (Queensland)	AGL (no third party access)	30*
Iona (Victoria)	Lochard (third party access)	26
Newstead (Queensland)	Armour Energy (sold to APLNG[61])	7.5*
Dandenong (LNG)	APA (third party access)	0.68
Newcastle LNG	AGL (no third party access)	1.5*

Source: AEMO, ACCC information, public websites

*These facilities are not reporting their storage capacity on the AEMO Natural Gas Services Bulletin Board. For these facilities, the capacity reported has been verified with the businesses or identified on websites.

In its 2015 inquiry the ACCC observed that producers were offering less flexibility to deal with variations in demand throughout the year and that storage was becoming more important as a risk management mechanism for gas buyers with variable loads, particularly in Victoria, New South Wales and South Australia.[62] This trend has continued, with the Gippsland Basin Joint Venture producers offering much less seasonal 'swing' in 2018 gas supply agreements. Peak demand will therefore need to be met from other sources. This could mean greater reliance on the large volume underground storage facility at Iona and other smaller pipeline and LNG storage services. Additionally, as occurred in winter 2017, peak southern demand could require the continued transportation of large quantities of gas from the north to the south.[63]

At present storage facilities in South Australia and Queensland are not playing a strong role to manage demand peaks and troughs.

4.6.2. Potential benefits of storage

Storage provides a number of potential benefits. It can be used to lower overall supply costs through taking advantage of variable (low-high) seasonal commodity pricing (e.g. filling in summer and withdrawing in winter). It also serves as a security of supply source and a risk management tool.

If gas prices fluctuate more across the year, large volume storage may become attractive. As shown in the chart below, Victorian gas prices have fluctuated more in 2016 and 2017 than in 2015.

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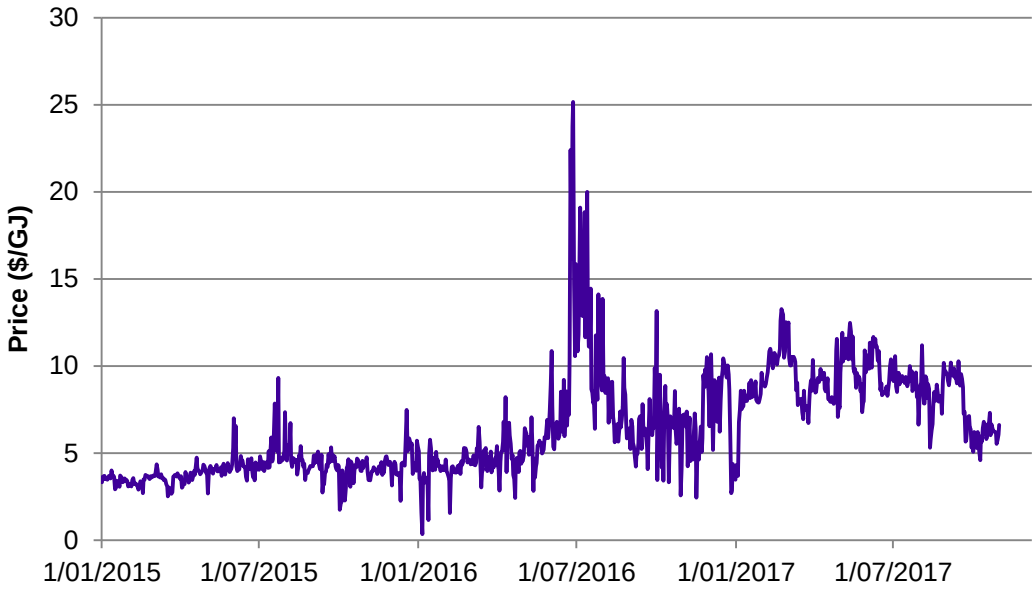
60 Excludes Ballera Gas Storage Facility as it is not in operation. AEMO: http://gasbb.com.au/~/media/Documents/Notices/2017/20170208%20Notice%20of%20Deregistration%20of%20Ballera%20Gas%20Plant%20and%20Chookoo%20Storage.pdf

61 http://www.lngworldnews.com/armour-energy-to-sell-feedgas-to-aplng/

62 ACCC, *Inquiry into the east coast gas market*, April 2016, p.94.

63 www.gasbb.com.au Gas flows reported on the Bulletin Board indicate an average of 82.5 TJ per day of gas delivered to Moomba from the South West Queensland Pipeline for the 3 months of Winter (June 1 to August 30).

Chart 4.4: Victorian Gas Market Daily Imbalance Price since 2015*



Source: AEMO; AER

* A $43/GJ price on 13 July 2016 has been removed from the chart, to make variations among other prices, all less than ~$25/GJ, more visible.

Higher within-year price differences create greater potential benefits from storage for a retailer seeking to minimise gas supply costs. A retailer could store gas purchased at a low price and sell it at a higher price. The actual benefit is dictated by the cost of purchasing that storage (these costs will be explored in more detail in a future report).

Variability in Asian spot market prices may influence the uptake of east coast gas storage. However, this will depend on the alignment of opportunities to purchase cheap Asian spot gas with opportunities to store that gas before the Australian winter. In the last two years, Asian prices have tended to be higher around our summer (the Asian winter) making that gas expensive to purchase and store at that time for the Australian winter. That said there might be opportunities in the "shoulder periods" around autumn or spring for gas, which might otherwise only achieve a low Asian spot price, to be diverted to storage and used over the Australian winter, this could be either via:

- Queensland producers delivering gas into storage in the South via the South West Queensland Pipeline (this could happen in part through the diversion of LNG exports)
- Global LNG being delivered into storage via a potential LNG import terminal, such as may occur through AGL's proposal for a terminal in Victoria[64]

Pipeline pricing may also influence use of storage. Currently the SWQP joining the north to the south is utilised unevenly–with far greater utilisation in winter. If capacity was sold on the SWQP and adjoining pipelines at lower prices in off peak periods this may further incentivise moving gas into southern storage. The GMRG led capacity trading reforms, which include the development of a day-ahead auction of contracted but un-nominated capacity, may drive such pricing differences and increased movement of gas when it is introduced in March 2019.

[64] AGL, *AGL announces Crib Point as preferred site for gas import jetty and pipeline*, 9 August 2017. Available here: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/august/agl-announces-crib-point-as-preferred-site-for-gas-import-jetty-and-pipeline Gas could also be stored in Northern storages, however this seems less likely given those storages are presently being depleted and given transportation constraints over winter from the north to the south

Storage also provides a system security benefit and risk management tool. Queensland storage in particular may assist when outages of LNG trains occur. However, it is unclear given present information reporting whether such events could be better managed through the parking of gas on pipelines and/or through agreements between exporters to take gas off each other.

A report by the Australian Energy Regulator in 2016 highlights Iona's key role in meeting Victorian / SA and NSW demand during a prolonged outage at a Queensland supply source. At that time, Iona was almost "drained" completely as market prices in these Southern states quickly escalated reaching prices at/or above $20/GJ on several days in July (see chart 4.4).[65] The scarcity pricing in markets at the time illustrates that, along with security of supply, storage can provide risk mitigation against market prices which can reach $800/GJ in Victoria.

4.6.3. Recent demand for storage and future proposals

The ACCC has observed increased marketing by pipeline operators of short-term storage capacity. A number of pipeline operators are enhancing revenue through park and loan services and this revenue is in some cases offsetting revenue reductions from less length-of-pipe transportation services. If a pipeline is not fully contracted to its delivery capability for transportation,[66] this increases the volume of potential storage for sale. For example, in the case of the TGP more gas can be stored on the pipeline near Victoria for peak period use through park and loan services. Across the Moomba Sydney pipeline, Eastern Gas Pipeline and Tasmanian Gas Pipeline (all servicing the Victorian market), there has been a significant increase in marketing of storage services. Two specific drivers of increased demand from users for pipeline storage are spot market price volatility in Sydney and Victoria, as well as the secondary market for providing balancing gas services (in Sydney). However, material from pipeline operators indicated where opportunities for sale of storage services existed, this did not necessarily convert to the same revenue as using that capacity to sell forward haul (length-of-pipe) services.

New or expanded underground gas storage facilities are also being actively considered. Material provided to the ACCC indicates that over the last 2 years a number of retailers, pipeline operators and potential new entrants have considered the development of new underground storage. More recently the Victorian Government has been exploring potential storage opportunities too.

Some current proposals are listed below.

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65 AER, *Significant price variation report, East Coast Gas Markets July & August 2016*, 14 November 2016. Available here: https://www.aer.gov.au/system/files/Significant%20price%20variation%20report%20-%20July%20%26%20August%202016.pdf,

66 For example, the Tasmanian gas pipeline (TGP) from Victoria to Tasmania.

Table 4.4: New Gas Storage Proposals being considered

Proposals	Description
Iona Gas storage expansion	Lochard Energy intends to increase its Iona UGS withdrawal capacity progressively from 2018 from 390 TJ/day to 570 TJ/day and storage injection from 153 TJ/day to 250 TJ/day through the workovers of two existing reservoir wells and addition of 1 or 2 new wells.[67] It is currently marketing increased WMDQ (withdrawal maximum daily quantities).
Newcastle LNG expansion	Although not large volume, recently AGL announced it has invested in plans to modify its LNG storage to allow further gas to be delivered to meet peak gas demands during winter. [68]
New Otway Storage	The Victorian Government is looking at the onshore Otway geological basin and investigating the potential for further underground gas storage sites.[69]
New Gippsland Basin Golden Beach Gas Storage	Golden Beach Gas Storage is an underground reservoir located adjacent to the Eastern Gas Pipeline in the Gippsland Basin near Longford which, once existing gas is extracted, could provide a quantity of usable storage of similar volume to Iona.
New Queensland Gas Storage	Opportunities in Queensland include new proposals related to underground salt caverns as well as the renewed usage of the Moomba / Ballera /RUGS facilities for refill and withdraw. As discussed in Chapter 1 both RUGS and Moomba are being depleted (the Ballera storage/production facility has not reported flows since mid-2015).[70]

Source: ACCC information, public websites

A potential impediment to storage development is that information on actual gas held in underground storages is only reported for the Moomba and Iona gas storages on the Bulletin Board presently. The adequacy of information on storage is something the ACCC will analyse in future reports, including the sufficiency of information available on pipeline line pack.[71]

[67] Lochard Energy, *Re: APA, Victorian Transmission System – Access Arrangement 2018-22.* Available here: https://www.aer.gov.au/system/files/Lochard%20Energy%20%E2%80%93%20APA%20Victorian%20Transmission%20System%20Access%20Arrangement%202018-22%20%E2%80%93%208%20March%202017.pdf

[68] ABC News, *AGL moves to shore up gas supplies to avert NSW energy crisis*. Access here: http://www.abc.net.au/news/2017-11-16/agl-moves-to-shore-up-gas-supplies-to-avert-nsw-energy-crisis/9156750

[69] http://earthresources.vic.gov.au/earth-resources/victorian-gas-program/gas-storage

[70] AEMO, *Actual Flow (INT 924, INT 925).* Available here: www.gasbb.com.au.

[71] Greater reporting will be facilitated on 30 September 2018 by a recent AEMC rule change, particularly as regards underground storage http://www.aemc.gov.au/Rule-Changes/Improvements-to-Natural-Gas-Bulletin-Board#

5. Supply outlook for 2020 to 2030

5.1. Key points

- The long-term supply-demand outlook for the East Coast Gas Market remains uncertain. Whether sufficient gas will be produced over 2020-2030 to meet the forecast East Coast Gas Market demand will depend on:
    - whether production from undeveloped 2P reserves will be realised, which will be significantly influenced by the performance of the CSG fields in Queensland
    - the success of development of contingent and undiscovered gas resources, the prospects and timing of which is highly uncertain
    - the level of domestic demand, which is currently quite uncertain
    - the level of LNG exports, particularly the quantity of the LNG spot sales.
- Security of future supply also requires a significant increase in the level of exploration and appraisal activity in the East Coast Gas Market, which in recent years has been stifled by the reduced price of oil as well as moratoria and regulatory restrictions in various states and territories of Australia.
- The long-term supply outlook is highly uncertain in the Southern States. There is little prospect of significant new sources of supply in the Southern States in the near-term:
    - most major known gas fields in offshore Victoria and the Cooper Basin have already been developed and are nearing depletion
    - there are only a limited number of new resources that have currently been identified for development, most of which are either highly uncertain or not expected to bring material quantities into the market
    - moratoria and regulatory restrictions in Victoria, NSW and Tasmania are impeding or preventing onshore exploration and development.
- Gas users in the Southern States will increasingly need to rely on gas imported from other supply regions, including Queensland, the Northern Territory or the international LNG market (should a regasification facility be built).
- On 1 December 2017, Arrow Energy announced that it had entered into a 27 year GSA with the QGC project, operated by Shell, which will pave the way for the development of over 6,000 PJ of Arrow Energy's 2P gas reserves in the Surat Basin. This is a very significant development for the East Coast Gas Market. Production is expected to commence around 2020 and will provide up to 240 PJ of additional gas. While most of this gas is expected to be exported, some of this gas is likely to be supplied into the domestic market.
- There are a number of other future potential sources of supply in Queensland and the Northern Territory which appear promising. There are also a number of new pipeline proposals that, if realised, will allow gas from these potential developments to be brought into the market and increase the overall East Coast Gas Market supply pool.
- However, any gas imported into the Southern States is unlikely to be cheap. The cost of transporting gas from Queensland to the Southern States is currently around $1.85–2.45/GJ, while the cost of transporting gas from the Northern Territory could be in excess of $5/GJ.
- As discussed in Chapter 4, there are currently also contractual and physical congestion issues on some of the major transmission pipelines between Queensland and the Southern States, which are making it more challenging to get the gas where it's needed.

- Further, the decline in the large gas reserves from developed offshore fields in Victoria is leading to an increased reliance on smaller, high impurity resources, which will require greater investment and will be more costly to produce. Over time, this may significantly increase the floor price of gas in the East Coast Gas Market. If there are cheaper onshore gas reserves that could be developed, particularly conventional gas reserves held by explorers like Lakes Oil, this could result in gas users, particularly in the Southern States, paying significantly less for gas.
- A number of state governments and the Australian Government have been implementing programs to strengthen the gas sector's future. For example the South Australian government's Gas Grants Scheme and the Queensland government's Gas Supply and Action Plan. These may result in more gas supply coming online in the medium to long term.

5.2. The long-term supply outlook remains uncertain

Chart 5.1 shows the long-term supply and demand forecast in the East Coast Gas Market for the ten year period 2020-2030. The production forecast is based on data obtained directly from producers and only includes expected production from 2P reserves. 2P reserves are reserves that, based on analysis of geological and engineering data, are more likely than not to be recoverable. That is, where there is at least a 50 per cent probability that the quantity of gas actually recovered will equal or exceed the estimated quantity. The chart does not include forecast production from contingent or undiscovered gas resources, which is presented separately in chart 5.2.

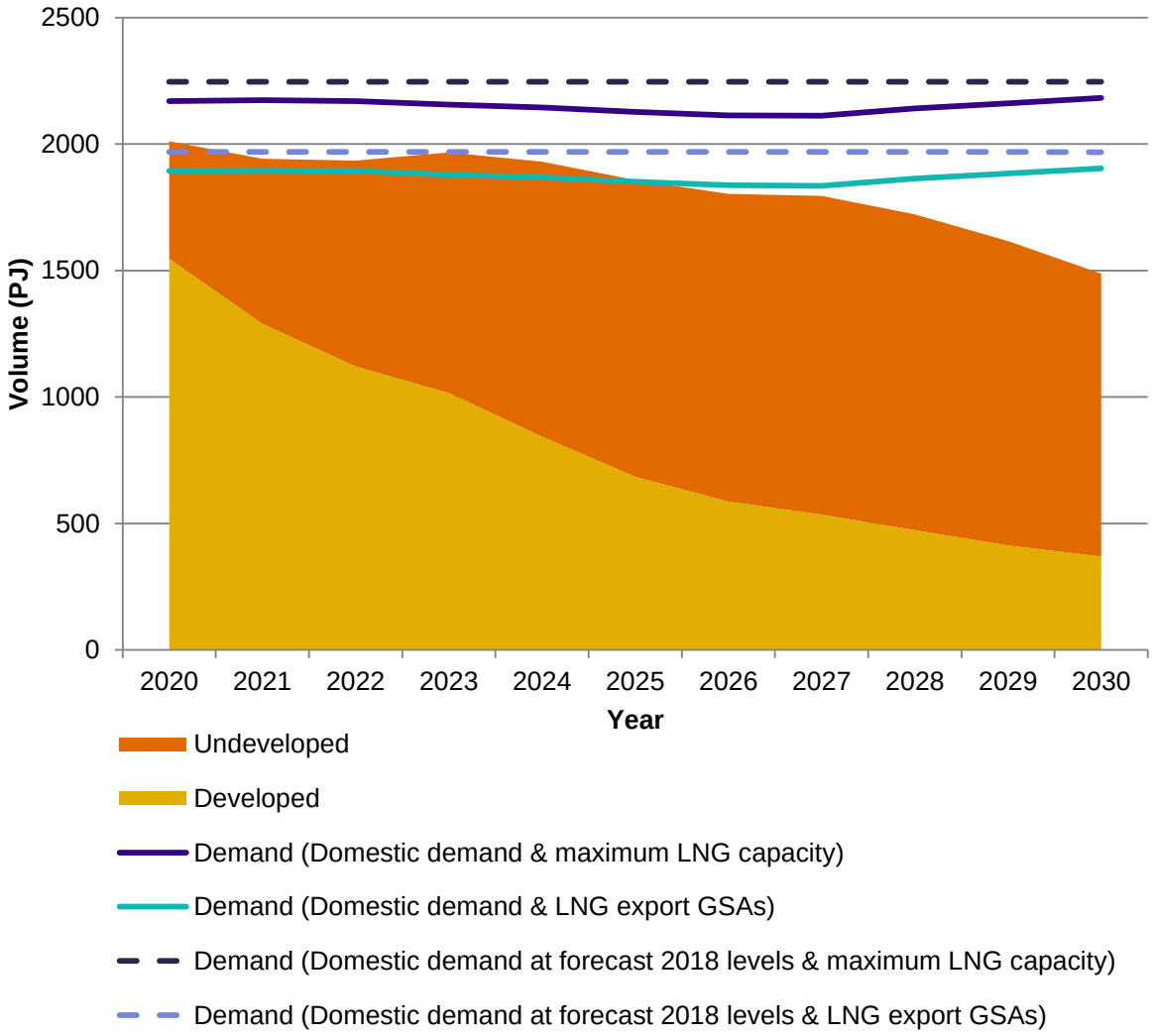
LNG export demand is also based on data obtained directly from producers. Domestic demand is based on AEMO's neutral plus increased GPG demand scenario[72] from its 2017 March GSOO (solid lines). This was the most recent long-term demand forecast available to the ACCC.[73] However, there have been a number of developments since March, particularly in relation to GPG, as reflected in AEMO's latest domestic demand estimates for 2018 and 2019. This means that domestic demand may be higher for 2020-2030 than previously forecast. For indicative purposes, the chart below also shows what the supply and demand outlook would look like if domestic demand was to remain at the recently forecast 2018 levels (dashed lines).[74]

[72] The neutral plus increased GPG demand scenario assumes neutral demand for the residential, commercial and industrial sectors, but a higher level of GPG demand in conditions where reliance on gas is increased.

[73] The ACCC understands an updated long-term demand forecast will be published by AEMO in 2018.

[74] Domestic demand based on AEMO data for 2019 from its September 2017 GSOO.

Chart 5.1: Forecast gas supply (including Arrow Energy and Northern Territory) compared to forecast gas demand, East Coast Gas Market, 2020-2030



Source: ACCC data and AEMO domestic demand data from its 2017 March GSOO and 2017 September GSOO.

Chart 5.1 shows a tight long-term gas supply outlook for the East Coast Gas Market. Whether production from 2P reserves will be sufficient to meet the East Coast Gas Market demand will depend on:

- whether production from undeveloped 2P reserves will be realised, which will be significantly influenced by the performance of the CSG fields in Queensland
- the level of domestic demand, which is currently quite uncertain
- the level of LNG exports, particularly the quantity of the LNG spot sales.

Unsurprisingly, the chart shows that over time, production from developed areas is expected to decline, and production from undeveloped areas will be increasingly relied on. As explained in our September 2017 report, production from undeveloped areas is somewhat less certain than production from developed areas. Unlike production from developed areas where gas is expected to be recovered through existing wells and for which the capital investment to undertake the production has already been made or committed, gas

production from undeveloped areas is expected to be recovered through new wells–the performance of which is not yet known–and may require approval of additional investments before production can commence. The ultimate timing of production of this gas will therefore depend on whether it is economic to invest in the development of these areas when it is required.

A further critical factor will be the performance of the CSG fields in Queensland, which are expected to account for a large proportion of future gas production. Coal seam gas production requires more wells than conventional gas production to achieve a satisfactory flow rate.[75] As CSG fields require more infrastructure, the cost associated with producing coal seam gas is generally higher than conventional gas production.[76] The need for continual reinvestment in CSG infrastructure creates ongoing commercial and technical uncertainty over the exact timing and quantity of future gas from these unconventional reserves.

With significant recent developments in gas and electricity markets, the future level of domestic gas demand is quite uncertain. As discussed in the September 2017 report, with GPG now playing a greater role in the electricity market, it is likely to have a greater influence on the future level of domestic gas demand. It is also not yet known how the C&I sector will respond to the higher gas and electricity prices. As chart 5.1 shows, if domestic gas demand for 2020-2030 were to maintain at the level recently forecast by AEMO for 2018 (the dashed lines), current forecasts of production from 2P reserves would not be sufficient to meet both domestic gas demand and LNG contractual commitments.

Further, chart 5.1 does not include forecast LNG spot sales. As these quantities of gas would be in addition to those required to meet long-term export GSAs, LNG spot sales would increase demand. This means that the degree to which production from 2P reserves is likely to meet demand will depend on the quantity of gas sold on the international LNG spot markets.

There is currently insufficient gas forecast to be produced from 2P reserves in the East Coast Gas Market to meet both domestic demand and allow the LNG projects to utilise their maximum LNG train capacity. If international LNG spot prices increase above their current levels and create incentives for the LNG projects to maximise LNG spot sales, this is likely to impact on availability of gas for the domestic market unless there is a corresponding increase in gas production.

Chart 5.2 assumes that the production in chart 5.1 will be realised and shows potential gas production from contingent and undiscovered resources against the remaining unfulfilled demand (that is, the difference between demand and production from 2P reserves, as presented in chart 5.1).

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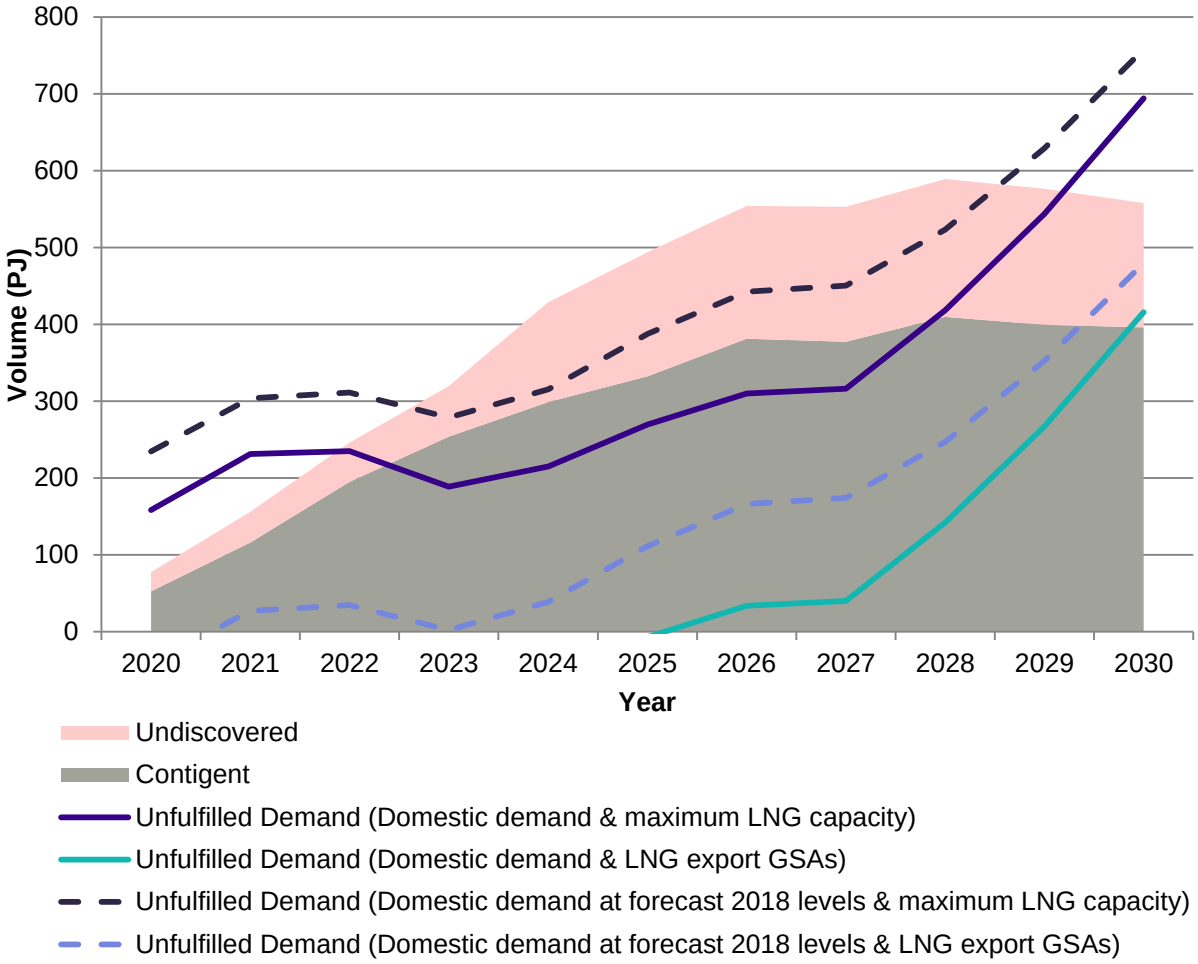
[75] Parliament of Australia, *The coal seam gas debate*, https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook44p/GasDebate

[76] Parliament of Australia, *The coal seam gas debate,* https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook44p/GasDebate

Chart 5.2: Unfulfilled demand and forecast production from contingent and undiscovered gas resources, East Coast Gas Market, 2020-2030



Source: ACCC calculations based on ACCC data and AEMO domestic demand data used for the 2017 March GSOO and the 2017 September GSOO.

Chart 5.2 shows that contingent and undiscovered gas production can potentially fill the supply 'gap' over 2020-2030 if forecasts are realised. There are a number of projects, discussed below, which are currently in the process of exploring for and appraising their resources. If these projects are successful, they could bring material additional quantities of gas into the market.

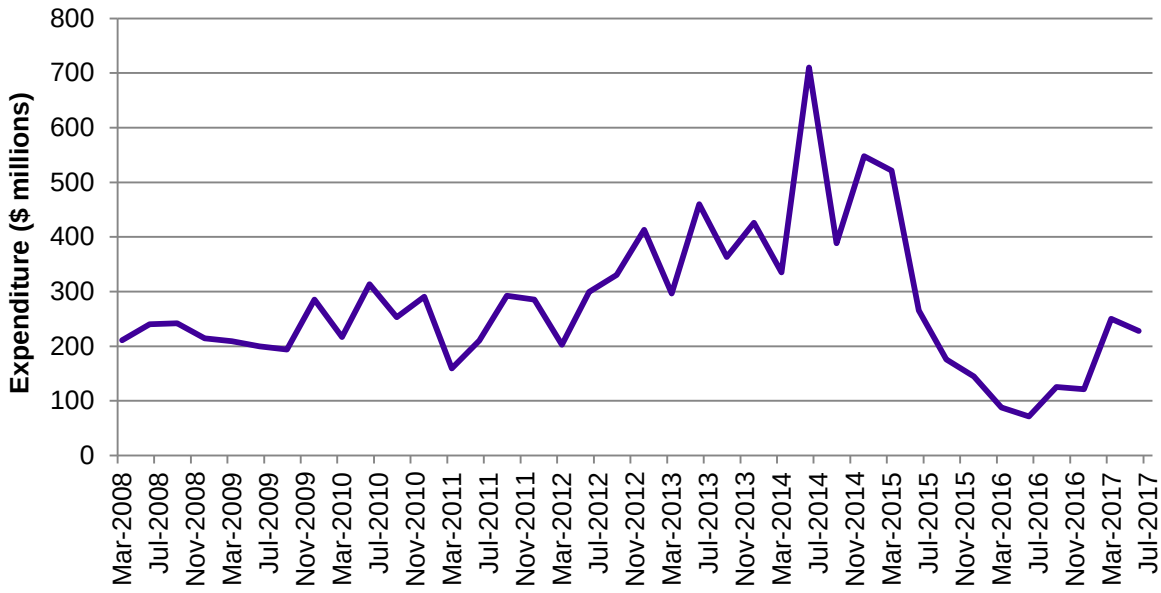
However, production from these types of resources is highly uncertain and will depend on the economics of exploration and development. Contingent resources are more challenging and technically difficult to extract and may require construction of additional infrastructure (such as treatment or conditioning facilities) to support the development process. Undiscovered resources are gas resources estimated to be potentially recoverable but that have not yet been proven by drilling. Additional testing and investment is therefore required before production commences.

The development of contingent and undiscovered resources in recent years has been hindered by the low price of oil (discussed further at section 5.2), which has stifled investment in exploration and appraisal activities. Moratoria and regulatory restrictions imposed in a number of the east coast states have also limited participation and investment in gas exploration and development.

According to data from the Australian Bureau of Statistics (ABS), overall petroleum[77] exploration expenditure across the east coast has been in significant decline since early 2015 (see chart 5.3). There was a slight increase in exploration expenditure in the March 2017 quarter but this was followed by a subsequent fall in the June 2017 quarter of about 9% (see chart 5.3). The ABS does not report separately on gas exploration expenditure, however as oil and gas are generally found and explored together, overall petroleum expenditure is likely to be indicative of the individual trend for gas. We'll explore trends in gas specific exploration activities in a future interim report.

The ABS data is consistent with reports by Energy Quest which indicate only 14 onshore exploration wells were drilled in the second quarter of 2017 compared to 16 in the previous quarter, and only one at the same time last year (the second quarter of 2016).[78] According to Energy Quest data as at 3 December 2017, only one exploration well has been drilled in offshore Australian waters in the past year.[79] However, this is expected to increase next year, with Energy Quest noting the potential drilling of up to ten wells.[80]

Chart 5.3—Petroleum exploration expenditure across the east coast (including Northern Territory), March 2008 - June 2017



Source: ACCC calculations based on ABS data.

It is important to note that there can be significant lead times between exploration and development activities–from when gas is first discovered to when it is developed for commercial use. This means more exploration needs to occur now, to ensure there is enough gas for production to meet demand in later years.

77 'Is a naturally occurring hydrocarbon or mixture of hydrocarbons. As oil or gas in solution (e.g. Liquid Petroleum Gas), it is widespread in Australian sedimentary rocks': http://www.abs.gov.au/Ausstats/abs@.nsf/glossary/8412.0

78 EnergyQuest, *EnergyQuarterly - September 2017*, p. 58.

79 EnergyQuest, *EnergyQuarterly - December 2017*, p. 50.

80 ibid., p. 50.

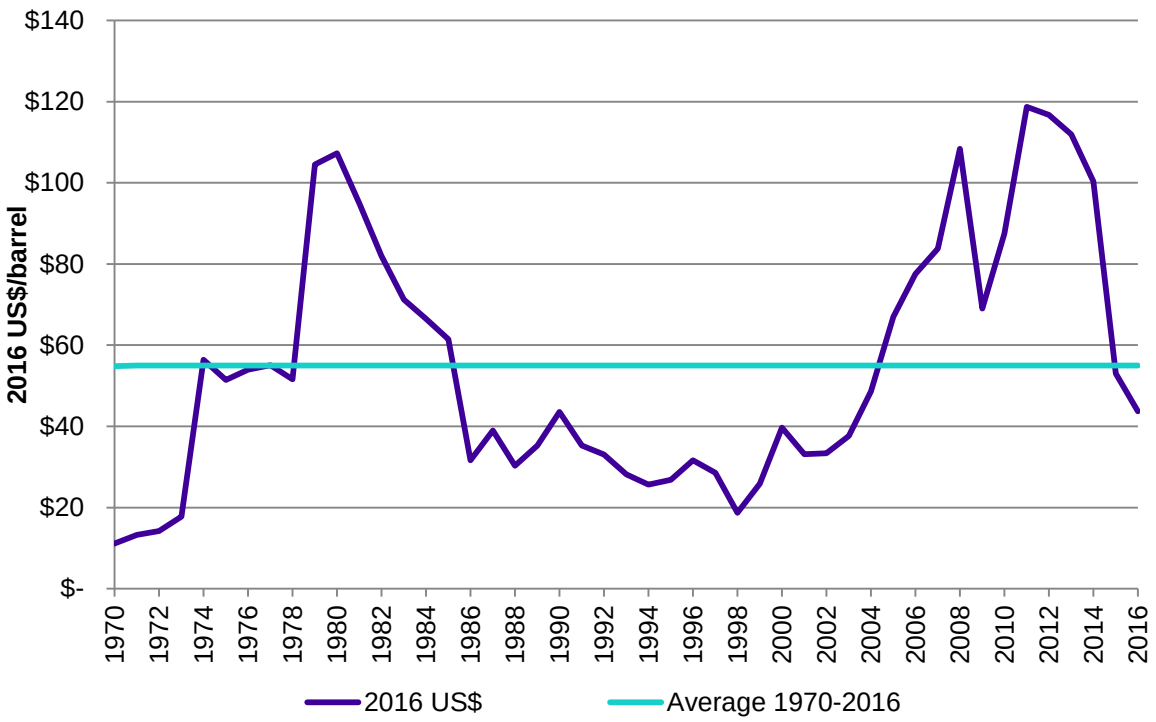
5.3. Oil prices are expected to remain around their long-term average in the near term

As explained in the ACCC's 2015 inquiry, commercial incentives to develop gas are linked to the global price of oil.[81] New investment in gas exploration tends to increase when oil prices are high, and decrease when oil prices fall. The LNG projects and major domestic suppliers (Santos, Origin Energy, and the GBJV) are all oil exposed–from being a party to, or having a financial interest in oil-linked GSAs, or being directly involved in the production and sale of oil.[82] Low oil prices mean lower sales revenue and earnings which, in turn, reduces the incentive, and means these businesses are less likely to invest in new gas exploration activities, or development opportunities, when oil prices are low.

The real average price of oil for the 1970-2016 (post OPEC[83]) period was US$55/barrel (in 2016 dollars; chart 5.4 below). Oil prices were highest in 2011 at an average of US$119/barrel, but then collapsed to an average of US$44/barrel in 2016 largely due to global over-supply.

As a consequence of the fall in the oil price, there has been a reduction in gas exploration activity (chart 5.3). A recent example of this is oil and gas company Chevron's abandonment of its drilling plans in the Great Australian Bight, attributable to "low oil prices [which] had forced it to concentrate on other projects".[84]

Chart 5.4: Real long-term oil prices, 2016 US$/barrel



Source: BP Statistical Review of Energy 2017.

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81 ACCC, *Inquiry into the east coast gas market*, April 2016, p.56.

82 ACCC, *Inquiry into the east coast gas market*, April 2016, p.57.

83 Organisation of the Petroleum Exporting Countries.

84 ABC News, *Chevron abandons drilling plans on Great Australian Bight, company blames low oil prices,* http://www.abc.net.au/news/2017-10-13/chevron-abandons-oil-drilling-on-great-australian-bight/9045870

As at 30 November 2017, the current Brent price of crude oil is US$63.41/barrel.[85] The Office of the Chief Economist forecasts Brent oil prices to average around US$55/barrel in 2018 and around US$57/barrel in 2019.[86] This, however, remains dependent on compliance with the OPEC Production Agreement (an agreement by member countries to reduce their oil production levels), and whether non-participating members to the Agreement (such as the US) continue to produce high levels of oil.

Even if oil prices improve beyond expectations, it may be some time before significant additional funds are invested into gas exploration, given the volatility of the oil market. Also, as mentioned above, even if producers invest in increased exploration activities, it may take many years before gas is developed and available to the market.

There are a number of potential sources of future supply in Queensland and the Northern Territory.

Queensland

As we reported in the September interim report, the bulk of the reserves in the East Coast Gas Market are currently held by producers in Queensland. As at 30 June 2016, the Department of Natural Resources and Mines (DNRM) estimated CSG reserves at 41,229 PJ, and conventional gas reserves at 370 PJ.[87]

Notwithstanding this, over the past few years, Queensland has been a net importer of gas as a result of significant quantities of gas being imported from outside Queensland, particularly the Cooper Basin, to meet the LNG demand. However, this is gradually changing and Queensland is increasingly becoming self-sufficient. As discussed in Chapter 1, the latest forecast for 2018 shows that production in Queensland is expected to be sufficient to meet Queensland's forecast domestic demand and expected exports (both under the long-term export contracts and forecast LNG spot sales).

Given the moratoria and other regulatory restrictions in place in a number of states and territories of Australia, Queensland appears to be the state most likely to materially increase gas production over the coming years, particularly following the recent announcement on development of Arrow Energy gas reserves (discussed further below). While production is currently limited to the Bowen and Surat basins, Queensland has a number of other basins which have potential and are currently being explored. These include the Galilee Basin, Clarence–Moreton Basin, Styx Basin, Cooper Basin, Eromanga Basin, Ipswich Basin, and Laura Basin.

Queensland is currently developing a Gas Supply and Demand Action plan in response to the economic and social challenges facing the sector.[88] The strategic plan will address four key themes: 1) characterising the Queensland gas sector in terms of risks, development potential and potential demand segments; 2) identifying the barriers to achieving least cost supply; 3) improving market transparency and 4) ensuring Queensland capitalises on all possible demand opportunities, including opportunities for greater GPG, gas-to-liquid and

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

86 Department of Industry, Innovation, and Science, *Resources and Energy Quarterly – September 2017*, https://industry.gov.au/Office-of-the-Chief-Economist/Publications/ResourcesandEnergyQuarterlySeptember2017/documents/Resources-and-Energy-Quarterly-September-2017-Oil.pdf

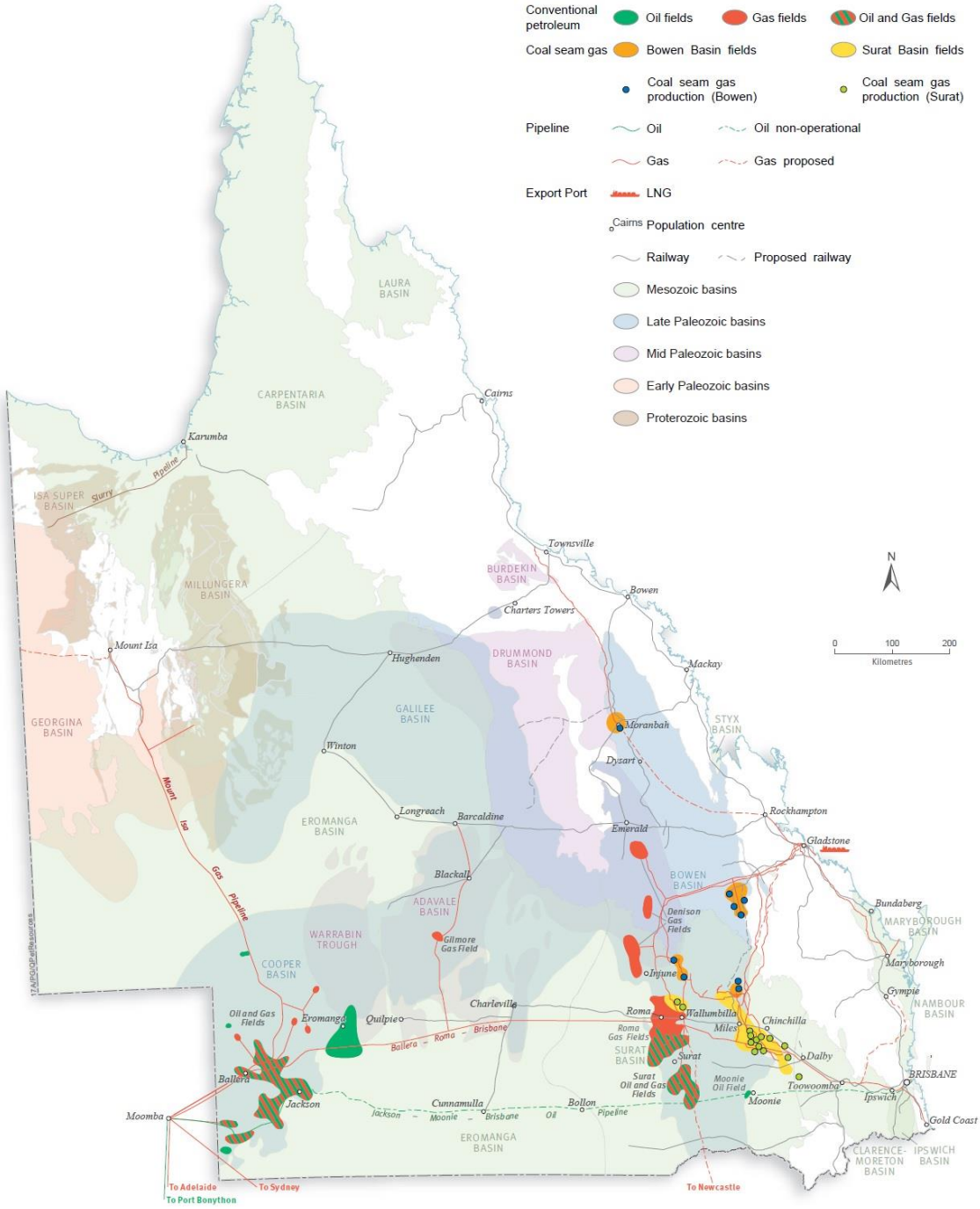
87 Queensland Department of Natural Resources and Mines, *Queensland's petroleum and coal seam gas*, January 2017, p. 1, https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0008/1237742/qld-petroleum-coal-seam-gas-2017.pdf

88 Queensland Department of Natural Resources and Mines, *Queensland Gas Supply and Demand Action Plan*, https://www.dnrm.qld.gov.au/our-department/corporate-information/policies-initiatives/mining-resources/gas-supply-demand-action-plan

manufacturing feedstock applications.[89] While this work is ongoing, it appears to be a positive step in balancing the interests of different stakeholders.

Figure 5.1 below illustrates the numerous gas basins across Queensland.[90]

Figure 5.1–Queensland's gas basins



89 Queensland Department of Natural Resources and Mines, *Terms of reference: Queensland Gas Supply and Demand Action Plan*, https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0012/621210/terms-reference-gas-action-plan.pdf

90 Queensland Department of Natural Resources and Mines, *Queensland's petroleum and coal seam gas*, January 2017, p. 2, https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0008/1237742/qld-petroleum-coal-seam-gas-2017.pdf

While there is potential for significant additional production in Queensland, over 95 per cent of this is expected to come from CSG reserves and resources. The costs of CSG production are expected to be higher compared to conventional gas production. This means that the CSG production costs are likely to set a relatively high floor for domestic gas prices.

Current developments

Arrow Energy

On 1 December 2017, a 27 year GSA between Arrow Energy (a 50-50 joint venture between Shell and PetroChina) and the QGC project (involving Shell, CNOOC and Tokyo Gas) was announced.[91] As a result of this GSA, over 6,000 PJ of Arrow Energy's previously uncontracted 2P gas reserves in the Surat Basin will be developed and supplied to the QGC project.[92]

This is a very significant development for the East Coast Gas Market. First gas production is anticipated around 2020 and could ramp up to 240 PJ per year (or 655 TJ/day). Given the current market conditions, this additional gas will improve the overall supply-demand balance in the East Coast Gas Market in the medium to long term. Undoubtedly this agreement will also result in additional quantities of gas being supplied to the domestic users, likely through Shell's recently established east coast gas and power trading business, although the extent of this is currently unknown.

The agreement was attributed in part to the cost efficiencies associated with using QGC's existing infrastructure (such as gas compression, processing, and water transport and treatment facilities).[93] The development of Arrow Energy's reserves also requires significant investment and it is unlikely that this development would have taken place in the short to medium term in the absence of a long-term GSA with an LNG exporter to underpin this investment.

While a final investment decision has not yet been reached[94], the project is likely to be sanctioned given the announcement of the GSA, the investment already undertaken or committed by Arrow Energy and the proximity of the reserves to existing QGC infrastructure.

Senex energy–project Atlas to increase domestic supply from the Surat Basin

As noted in our September 2017 report, the Queensland government announced Senex had secured the rights to a petroleum lease on 58 square kilometres of coal seam gas acreage in the Surat Basin.[95]

The tender marked the first time provisions of resources legislation had been used to direct gas to the domestic market.[96]

The acreage contains recoverable gas quantities of 201 PJ.[97] Senex plans to drill around 100 wells to sustain gas production of over 30 TJ/day at plateau, and is targeting first gas in 2019.[98]

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[91] Arrow Energy, *Arrow Energy agrees deal for Surat Basin reserves*, Media release, 1 December 2017, https://www.arrowenergy.com.au/__data/assets/pdf_file/0004/23638/Arrow-Energy-GSA-media-release.pdf

[92] ibid.

[93] Ibid.

[94] Shell Australia, *Statement from Shell – Arrow Gas Sales Agreement*, 1 December 2017, http://www.shell.com.au/media/2017-media-releases/arrow-gas-sales-agreement.html

[95] September 2017 report, p. 40.

[96] Queensland Government media release, *Palaszczuk Govt ramps up domestic gas supply*, 5 September 2017.

[97] This is a P50 estimate.

Senex has announced it will engage with domestic gas customers in early 2018 with a view to signing GSAs. During the tender process, Senex received expressions of interest from domestic customers totalling over 150 TJ/day of combined demand.

The Queensland government has since released two more prospective areas for exploration in Queensland's Bowen and Surat basins via competitive tender, each with a condition to supply the domestic market. Responses close early December this year, with preferred tenderers expected to be announced in the first quarter of 2018.[99]

Potential opportunities

Origin's Ironbark project–Surat Basin

Origin has announced its aiming to enter FEED (front end engineering design) on a Phase 1 Development concept for the Ironbark project during FY2018.[100] Origin has previously indicated to the market that Ironbark production could commence in the 2021 financial year, although this is subject to the outcomes following the FEED work.

The Ironbark project relates to exploration permit ATP 788P, which was acquired in April 2009.[101] Origin's most recent estimates of Ironbark's reserves are 249 PJ (2P), 635 PJ (3P), and 332 PJ (2C).[102]

There is reason to suggest some of the gas produced may be for export markets. When Origin acquired the asset, it noted its joint venture arrangement with ConocoPhillips meant APLNG had the right to acquire the interest prior to completion. Also, in March 2016 when it announced the signing of a non-binding agreement to supply over 25 PJ of LNG[103] to ENN LNG Trading over five years, Origin referred to the Ironbark project as being an economic source of supply for ENN when tolled through existing LNG infrastructure and can be developed at a time when it becomes the lowest cost source of supply.[104]

Galilee Energy's Glenaras project–Galilee Basin

Galilee describes the Glenaras Gas Project in the Galilee Basin as having one of the largest remaining uncontracted gas resources on the east coast of Australia with independently derived and certified contingent resources of 308 PJ (1C), 2,508 PJ (2C), and 5,314 PJ (3C).[105] Galilee currently forecasts to commence production in about 3-4 years with production potentially ramping up to about 70 PJ per annum. However, this timing is highly uncertain as the project has not yet been sanctioned.

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98 Senex, *Quarterly Report – Q1 FY18 September 2017*, page 1, https://www.senexenergy.com.au/wp-content/uploads/2017/10/2017.10.25-September-2017-Quarterly-Report.pdf

99 Queensland Government media release, *Palaszczuk Government opens more land for domestic gas supply*, 6 September 2017.

100 Origin, *Origin Energy Annual General Meeting 2017*, 18 October 2017, http://www.asx.com.au/asxpdf/20171018/pdf/43nb7zr24bmds2.pdf

101 Origin, *Origin to acquire a further 1,150 PJ (3P) of CSG reserves straddling the Undulla Nose CSG sweet spot*, 22 April 2009, http://www.asx.com.au/asxpdf/20090422/pdf/31h5ggrjg144qc.pdf

102 Origin, *Origin Energy 2017 Annual Report*, http://www.asx.com.au/asxpdf/20170914/pdf/43mb3nq5sdxgz4.pdf

103 ACCC conversion from 500 000 tonnes of LNG.

104 Origin, *Origin signs non-binding agreement to supply LNG to ENN*, 1 March 2016, https://www.originenergy.com.au/about/investors-media/media-centre/non-binding-agreement-to-supply-lng-to-enn.html

105 Galilee Energy, *Galilee Energy and Jemena fast-track pipeline*, ASX announcement, 17 October 2017, http://galilee-energy.com.au/wp/wp-content/uploads/2017/10/Galilee-Energy-and-Jemena.pdf

On 17 October 2017, Jemena and Galilee Energy announced plans to work together towards delivering gas from the Glenaras Gas Project to the East Coast Gas Market.[106] Initially, this will involve Jemena completing pipeline design work. At this stage it appears the pipeline could in effect extend the NGP from Mount Isa towards the Wallumbilla region.

APA's Reedy Creek to Wallumbilla pipeline

APA is constructing a new pipeline linking the Wallumbilla Gas Supply Hub (WGSH) and the APLNG pipeline at Reedy Creek. This would improve the ability of APLNG to trade gas at the WGSH. APA has entered into a 20 year contract with APLNG Marketing to provide a bi-directional service of up to 300 TJ/day. The pipeline is expected to be completed in 2018.[107]

Other exploration in Queensland

Comet Ridge

Comet Ridge has interests in three permits in the Galilee Basin and one in the Bowen Basin (the Mahalo project).

The Mahalo project is located 14 kilometres from infrastructure linking it to Gladstone. Comet Ridge holds a 40 per cent interest, with Santos QNT Pty Ltd and APLNG each holding 30 per cent respectively. Comet Ridge has independently certified 30 PJ of 2P reserves, 219 PJ of 3P reserves, and 112 PJ of 1C contingent resources for its interest in the asset. Exploration work is ongoing.[108]

Comet Ridge has a very large acreage in the eastern part of the Galilee Basin. This acreage has been lightly explored; however it has been independently certified to have significant 3C contingent resources. Comet Ridge has been in discussions with gas purchasers, transporters and the Queensland Government about the future supply of gas and the construction of associated infrastructure.[109]

Blue Energy

Blue Energy has interests in the Bowen, Carpentaria, Cooper/Eromanga, Galilee, Maryborough, Surat, and South Georgina Basins.

In the Bowen Basin, Blue Energy estimates it has 71 PJ of 2P reserves, and 298 PJ of 3P reserves. Blue Energy notes the commercialisation of this resource will be influenced by Arrow Energy's investment decision regarding its Moranbah assets including the Moranbah to Gladstone pipeline.

For the Galilee Basin, Blue Energy estimates the resource to be around 62 PJ of 2C and 838 PJ of 3C reserves. Blue Energy's exploration in the Surat Basin has resulted in estimated resources of 22 PJ (1C), 47 PJ (2C), and 101 PJ (3C).

Blue Energy does not have estimates for its other interests, as they are in the early stages of exploration.[110]

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106 Galilee Energy, *Galilee Energy and Jemena fast-track plans to connect Galilee Basin to the East Coast gas market*, ASX/media announcement, 17 October 2017, http://galilee-energy.com.au/wp/wp-content/uploads/2017/10/Galilee-Energy-and-Jemena.pdf

107 APA, *Reedy Creek Wallumbilla Pipeline*, https://www.apa.com.au/about-apa/our-projects/reedy-creek-wallumbilla-pipeline/, accessed 27 October 2017.

108 Comet Ridge, *Annual Report for the Year Ended 30 June 2017*, p. 2.

109 ibid., p. 3.

110 Blue Energy, *Projects*, https://blueenergy.com.au/projects, accessed 27 November 2017.

Real Energy

Real Energy is conducting exploration in the Cooper and Eromanga Basins. It estimates its resources as 276 PJ (2C) and 672 PJ (3C).[111] [112]

While exploration is continuing, Real Energy executed a non-binding memorandum of understanding (MOU) with Weston Energy in July this year. Real Energy described the MOU relates to the purchase of 3 PJ per year for a period of five years. It is subject to a number of conditions, including Weston Energy finalising transportation arrangements.[113]

Northern Territory

Introduction

The Northern Territory will be connected to the East Coast Gas Market upon the completion of Jemena's Northern Gas Pipeline (NGP), which is expected to flow gas in late 2018.[114] The NGP is discussed further in the next section.

Gas production in the NT is currently limited to two basins; the Amadeus Basin (onshore) and the Bonaparte Basin (offshore). The under construction Ichthys LNG project will have its gas processing facility in Darwin, which will process gas sourced from the Browse Basin (located about 220 kilometres off the coast of Western Australia). Production from Ichthys is scheduled to commence around March 2018.[115]

The NT's domestic gas demand relates almost entirely to electricity generation in the three zones of Alice Springs, Tennant Creek and the main Darwin-Katherine electricity networks. For 2016, the NT's annual gas demand was estimated to be less than 30 PJ.[116] This means that the bulk of production from the NT will need to be exported either into the east coast or overseas.

While onshore production is currently limited to one basin, the NT is home to a number of onshore basins with the potential to supply significant quantities of gas. However exploration and production from these basins has been put on hold due to the NT Government's moratorium on hydraulic fracturing of onshore unconventional reservoirs and the related independent scientific inquiry.[117] Figure 5.2 below was produced by the independent scientific inquiry and illustrates the onshore basins of the NT.

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111 Real Energy, *121 Oil & Gas Conference*, 30 October 2017, slide 13.

112 These volumes were originally reported as billion cubic feet (BCF). We converted using 1 BCF = 1 PJ.

113 Real Energy, *Real Energy signs gas sale MOU with Weston Energy*, ASX announcement, 17 July 2017.

114 Jemena, *Northern Gas Pipeline*, http://jemena.com.au/industry/pipelines/northern-gas-pipeline, accessed 25 October 2017

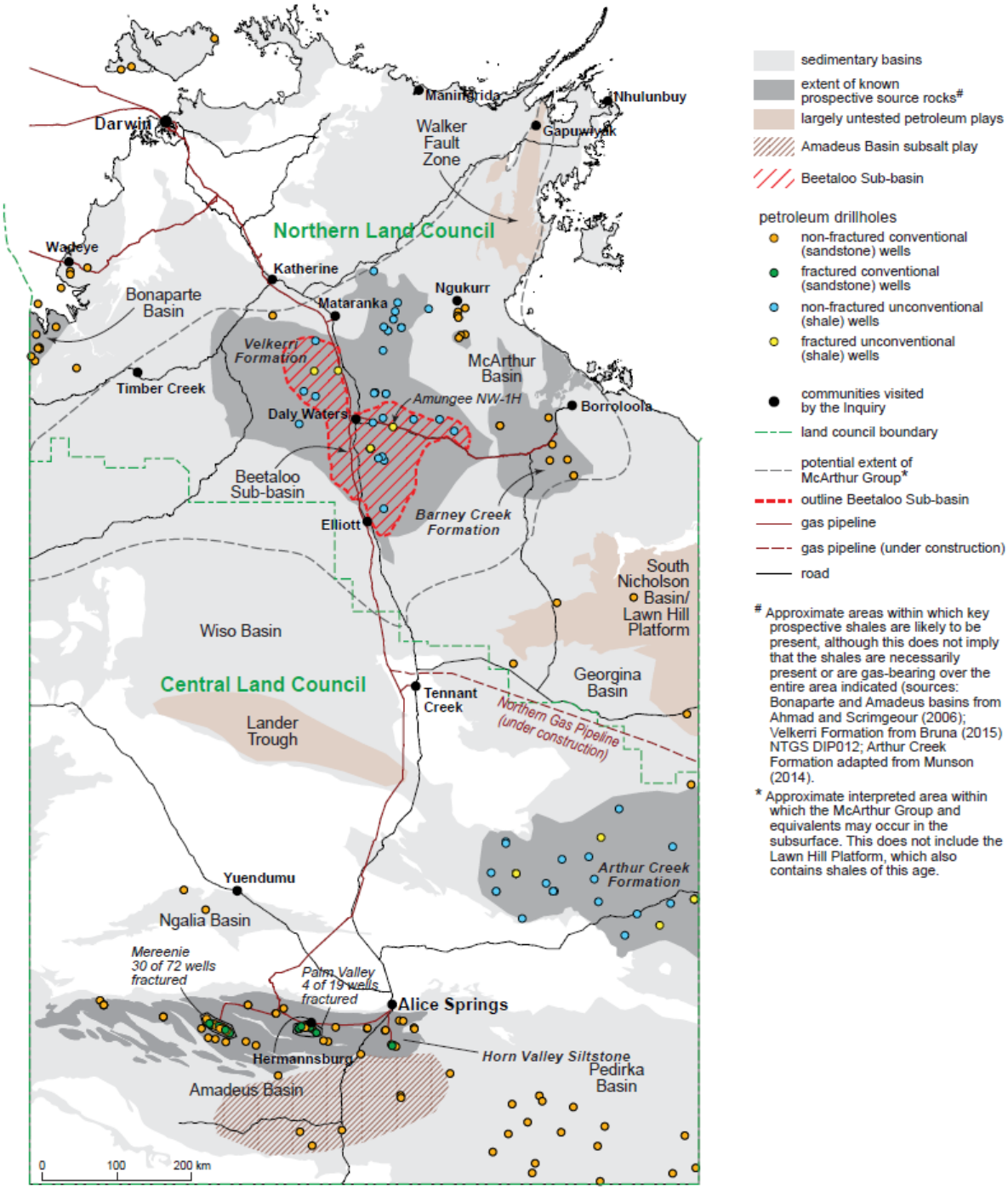
115 INPEX, *Ichthys in detail*, http://www.inpex.com.au/our-projects/ichthys-lng-project/ichthys-in-detail/project-overview/, accessed 1 November 2017.

116 Oakley Greenwood, *Gas Price Trends Review – February 2016*, page 69.

117 Hydraulic Fracturing Taskforce, *The scientific inquiry into hydraulic fracturing in the Northern Territory*, https://frackinginquiry.nt.gov.au/, accessed 24 October 2017.

Figure 5.2–Petroleum wells in the NT showing extent of known prospective source rocks[118]

Figure 1: Petroleum wells in the NT showing extent of known prospective source rocks. Source: Department of Primary Industry and Resources.



Currently, production from the Amadeus Basin is from conventional gas fields operated by Central Petroleum (Central).[119] The Macquarie Group has an interest in some of the gas produced, which was recently acquired from Santos. Production from Central has not been impacted by the moratorium as hydraulic fracturing is not required.

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118 https://frackinginquiry.nt.gov.au/interim-report

119 The Mereenie, Palm Valley, and Dingo fields – http://centralpetroleum.com.au/about/company-overview-strategy/

Production from the Bonaparte Basin relates to the Eni operated Blacktip field, and the Bayu Undan field which supplies gas for export by the Darwin LNG project.

Eni's Blacktip gas field commenced in 2009 and is connected to an onshore treatment plant. Gas produced is sold under a 25 year GSA with the Northern Territory Government owned Power and Water Corporation (PWC).[120] PWC entered the supply arrangement to secure gas for power generation.[121]

The Darwin LNG plant was officially commissioned in January 2006. The Bayu Undan field is connected to a plant where it is converted to LNG for sale to Tokyo Gas and JERA (a joint venture between Tokyo Electric and Chibu Electric). ConocoPhillips is the majority interest holder and operator of the field, the pipeline, and the LNG plant.[122] Santos, INPEX, Eni, JERA and Tokyo gas each have an interest in the project. The Bayu Undan field is expected to cease production after 2022. ConocoPhillips is currently investigating options to ensure continued gas supply to the project.[123]

Current developments

The Northern Gas Pipeline

As noted above, and in our September 2017 report, the completion of the NGP in late 2018 will result in the NT becoming a new source of supply for the East Coast Gas Market.

The NGP will run from Tennant Creek[124] in the NT to Mount Isa in Queensland[125], and is expected to allow for the transportation of 30–35 PJ of gas per annum–or around 90 TJ/day.

PWC is the foundation customer of the NGP.[126] PWC will supply 30 TJ/day (or 11.4 PJ a year) to Incitec Pivot's Phosphate Hill site in North West Queensland for approximately 10 years to 2028.[127] We understand this gas is sourced from the Blacktip field off the coast of the NT.[128]

While around 60 TJ/day of pipeline capacity remains for new sales, Jemena expects capacity to be fully booked by the time the pipeline is completed.[129]

Acil Allen's final report to the independent scientific inquiry puts forward a different view. The report states that "apart from the gas being sold into the project by the Northern Territory government from its Blacktip entitlements, no other gas supply has yet been committed to

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120 Eni, *Eni's activities in Australia*, https://www.eni.com/enipedia/en_IT/international-presence/asia-oceania/enis-activities-in-australia.page, accessed 1 November 2017.

121 Eni, *The Blacktip Gas Field and the Yelcherr Gas Plant*, https://www.eni.com/en_IT/media/focus-on/australia/blacktip_gas_field_yelcherr_gas_plant.page, accessed 1 November 2017.

122 ConocoPhillips, *Darwin LNG*, http://www.conocophillips.com.au/our-business-activities/our-projects/Pages/darwin-lng.aspx, accessed 1 November 2017.

123 ibid.

124 At Tennant Creek, the NGP will be connected to APA's Amadeus Gas Pipeline – which links Darwin, Alice Springs, and other regional centres.

125 At Mount Isa, the NGP will be connected to APA's Carpentaria Gas Pipeline – which runs from Mount Isa to the South West Queensland Pipeline at Ballera.

126 PowerWater, *Power and Water positioned to enter the Australian gas market*, 17 July 2017, https://www.powerwater.com.au/news_and_publications/news/2017/power_and_water_positioned_to_enter_the_australian_gas_market, accessed 24 October 2017.

127 Central Petroleum, *Interim Financial Report – half year ended 31 December 2015*, page 1 http://www.asx.com.au/asxpdf/20160315/pdf/435vv4fkzddxyn.pdf

128 PowerWater, *What we do – gas supply*, accessed 26 October 2017, https://www.powerwater.com.au/about_power_and_water/what_we_do

129 AFR, *Jemena 'close' to signing up second customer for Northern Gas Pipeline*, 23 July 2017, http://www.afr.com/business/energy/gas/jemena-close-to-signing-up-second-customer-for-northern-gas-pipeline-20170721-gxgaww

the project. The Blacktip gas has effectively been committed to the Mount Isa market in Queensland (which has an annual gas requirement comparable to the annualised throughput capacity of the NGP in its current configuration). Under current policy settings, NGP does not appear likely to deliver large quantities of competitively priced gas into the east coast market".[130]

We understand the NGP's capacity could be increased from 90 TJ/day to 160 TJ/day with compression.[131] Jemena has claimed its modelling suggests that the pipeline can be easily expanded and extended to transport up to, or beyond, 700 TJs of gas per day.[132]

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130 Acil Allen Consulting, *The economic impacts of a potential shale gas development in the Northern Territory*, Final Report October 2017, page 18, https://frackinginquiry.nt.gov.au/news/?a=456788

131 Central Petroleum, *Equity Raising – Investor Presentation*, ASX announcement, 10 August 2017, https://wcsecure.weblink.com.au/pdf/CTP/01882783.pdf

132 Jemena, *$800 million gas pipeline to bring Northern Territory gas to the east coast*, media release 12 July 2017, https://jemena.com.au/about/newsroom/media-release/2017/gas-pipeline-to-bring-northern-territory-gas-to-th

Box 5.1: Bringing gas from the NT into the East Coast Gas Market

For gas from the NT to be commercially attractive to gas users in the East Coast Gas Market, particularly those in the Southern States, the delivered price of NT gas must be competitive with the delivered gas prices being offered by other suppliers. The two main drivers behind the delivered price of NT gas into the East Coast Gas Market are the costs of production and transportation.

This box provides indicative transportation costs for delivery of gas from the NT to different locations in the East Coast Gas Market. The prices in this box are for illustrative purposes only – prices actually paid may differ. We have also seen some evidence of APA offering a discount to shippers who require transportation across multiple pipelines owned by it.

In order to transport gas from the NT to Ballera, the following pipelines will need to be used (with indicative tariffs taken from invoices seen by the Inquiry, with the exception of the NGP where the tariffs are from Jemena's website):

- APA's Amadeus Gas Pipeline (AGP), which runs from Darwin to the Amadeus Basin in the south (while there is currently no firm capacity available on the AGP, tariffs are around $0.60–0.65/GJ)
- Jemena's Northern Gas Pipeline (NGP), which connects to the AGP at Tennant Creek in the NT, and runs to Mount Isa in Queensland ($1.45/GJ firm forward haulage and $0.74/GJ for firm nitrogen removal service – total of $2.19/GJ)
- APA's Carpentaria Gas Pipeline (CGP), which connects to the NGP at Mt Isa and runs to Ballera in South West Queensland ($1.15–1.61/GJ – these rates are for forward haul from Ballera to Mt Isa. If the volumes to flow south are less than the volumes flowing to Mt Isa then a backhaul service will be required. While such services are typically sold at a discount to forward haul services, we understand APA's tariffs for backhaul are similar to forward haul).

For these three pipelines, the combined transport cost comes to around $3.94–4.45/GJ.

From Ballera, shippers may choose to transport gas:

- east, to Wallumbilla, using APA's South West Queensland Pipeline (SWQP) ($0.89–1.39/GJ)
- west, to Moomba, using the QSN link, which is the Ballera to Moomba leg of the SWQP ($0.24/GJ – for the purpose of this box, we are assuming the tariff for western haul services would be the same as for eastern haul).

This brings the total cost of transportation to around $4.82–5.84/GJ to transport gas from the NT to Wallumbilla and around $4.18–4.69/GJ to transport gas from the NT to Moomba.

From Moomba, suppliers may choose transport gas:

- to Sydney, using APA's Moomba to Sydney Pipeline (MSP) ($0.83–0.97/GJ)
- to Adelaide, using Epic Energy's Moomba to Adelaide Pipeline System (MAPS) ($0.64–0.72/GJ).

This brings the total of transportation to around $5.01–5.66/GJ to transport gas from the NT to Sydney and $4.82–5.41/GJ to transport gas from the NT to Adelaide.

At these prices, the NT gas is unlikely to be competitive in the East Coast Gas Market, particularly the Southern States. Suppliers will likely need to negotiate better prices for transportation to make delivered price of NT gas attractive to gas users in the East Coast Gas Market.

Central Petroleum's drilling program to increase gas reserves

Central is planning to drill four wells (without hydraulic fracturing) with the objective of substantially increasing its gas reserves in time to have delivery coincide with the NGP becoming operational.[133] In September this year, Central completed a successful capital raising to fund the work. The results of the program are expected to be known mid to late 2018.

[133] Central Petroleum, *Equity Raising – Investor Presentation*, ASX announcement, 10 August 2017, https://wcsecure.weblink.com.au/pdf/CTP/01882783.pdf

The moratorium and scientific inquiry–and the impact on the East Coast Gas Market

On 14 September 2016, the NT government announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs. An independent scientific inquiry has also been commissioned, with its final report expected by the end of the year.[134]

As the gas expected to flow from the NGP into the East Coast Gas Market is sourced from the offshore Blacktip field, this supply will not be impacted by the moratorium. This is also the case in respect of any gas supplied from Central's operations.

With this in mind, and noting Jemena's expectations that the NGP will be fully booked by the time the pipeline is completed, it seems unlikely that the current moratorium will reduce the quantity of gas delivered from the expected 90 TJ/day.

However, Jemena has said any expansion of the NGP would require more gas being available in the NT–the likelihood of which is limited by the moratorium.[135]

Because of the moratorium, a number of projects across the territory have been put on hold. Some of these are discussed below.

Potential opportunities

Origin–Beetaloo sub basin

In February this year, Origin announced that recent test results indicated the existence of a material gas resource within the Beetaloo Basin, which is a sub basin of the McArthur Basin.[136] The shale gas reservoir is located north of Tennant Creek and near the Amadeus Gas Pipeline (AGP). Origin announced its best estimate of 'Estimate Gas Contingent Resource category of 2C' as 6.6 trillion cubic feet (TCF), which is nearly 7000 PJ.

Four exploration and appraisal wells have been drilled to date. There are five wells remaining under the three-stage exploration and appraisal program. This program is currently on hold pending the moratorium.

The ACCC understands that if Origin recommenced its appraisal process in the 2019 financial year, it could potentially supply gas to the East Coast Gas Market from the mid 2020s.

McArthur Basin

Blue Energy is the operator of blocks covering 111 887 square km of the McArthur Basin, in the NT. This is located around 200 km to the west of Origin's Beetaloo resource. The permits for this resource have been placed in suspension until the NT Government indicates its stance on hydraulic fracturing.[137]

Armour Energy also holds interests in the McArthur Basin, however, the moratorium has halted Armour Energy's activities. Armour Energy had already conducted some exploratory

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134 Hydraulic Fracturing Taskforce, *The scientific inquiry into hydraulic fracturing in the Northern Territory*, https://frackinginquiry.nt.gov.au/, accessed 24 October 2017.

135 ABC News, *Construction of the Northern Gas Pipeline begins in Tennant Creek*, 13 July 2017, http://www.abc.net.au/news/rural/2017-07-12/construction-on-northern-gas-pipeline-begins-in-tennant-creek/8700332

136 Origin, *Beetaloo Basin drilling results indicate material gas resource*, ASX announcement, 15 February 2017, http://www.asx.com.au/asxpdf/20170215/pdf/43g0qhh87j71bb.pdf

137 Blue Energy, *Quarterly Activities Report – To 30th September 2017*, page 9, https://blueenergy.com.au/files/media/blue_energy_september_quarterly_2017_final.pdf

work the results of which include 193 conventional leads prospects targeting 4.9 TCF (over 5,100 PJ) of gas prospective resource.[138]

Santos also has significant interests in the McArthur Basin, with interests in three prospective shale gas and oil permits with applications pending for a further two permits. Santos' exploration in the area is limited to the Tanumbirini-1 exploration well which has been suspended for the time being.[139]

Ebony Energy's coal to gas 'Andado project' and pipeline to Moomba in South Australia

On 5 October this year, Ebony Energy announced the completion of a scoping study for what could be Australia's first above ground coal-to-gas production project.[140] The project is located in the NT, around 250 km south of Alice Springs at the Andado cattle station.

Ebony claims the project could begin to supply more than 50 PJ a year to the East Coast Gas Market within the next five years, using a purpose built pipeline from the plant to the Moomba gas hub.

The project would use coal from the Pedirka Basin, brought to the surface using underground mining techniques. The coal would then be converted to gas in an above ground gasifier plant next to the mine site.

Ebony has entered into an MoU with GE regarding the plant, and an MoU with OSD regarding the development and operation of the pipeline.

5.4. There is currently little prospect of increase in production in the Southern States in the short to medium term

As we set out in the September 2017 report, production in the Southern States is currently not sufficient to meet the domestic demand in the Southern States. Based on the current short-medium term supply outlook, this is set to continue. There are currently few potential sources of future supply identified in the Southern States that are likely to commence production in the next 5 years and their combined output is not likely to be material.

As identified in the Offshore South East Australia Future Gas Supply Study, there are limited short-term prospects of development of south east Australia's offshore gas resources and the level of exploration activity is very low. As discussed earlier in Chapter 1, there is currently very little prospect of increase in supply from the GBJV, the region's largest gas producer.

There are a number of potential onshore gas resources that could be developed. However, moratoria and regulatory restrictions in New South Wales, Victoria and Tasmania are preventing or limiting the exploration and development of onshore gas resources. The timing and likelihood of some of the prospective projects in the Cooper Basin is currently highly uncertain.

While this continues, gas users in Southern States will have to rely on declining off-shore gas production in the Bass Strait and, increasingly, on gas production from Queensland to

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138 Armour Energy, *Northern Territory*, https://www.armourenergy.com.au/northern-territory/, accessed 26 October 2017.

139 Santos, *What we do - McArthur Basin*, accessed 26 October 2017, https://www.santos.com/what-we-do/activities/northern-territory/mcarthur-basin/

140 Ebony Energy, *The Andado Project Company Release*, media release, 5 October 2017, http://www.ebonyenergy.net/press-room/62-the-andado-project-company-release.html

meet their needs. Inevitably this means gas users in the Southern States will have to face higher gas prices.

Victoria

In Victoria, gas production is currently all offshore in the Otway and Gippsland basins due to legislative constraints and moratoria preventing onshore exploration and development of both conventional and unconventional gas.

This dates back to 24 August 2012, when the Victorian government imposed a moratorium on onshore coal seam gas exploration and the use of fracking, which was later expanded in May 2014 to impose a blanket ban and prohibit all onshore gas exploration and production activities.

In March this year, the state government amended the law to permanently ban the use of fracking and the exploration of coal seam gas in Victoria.[141] The government also extended the moratoria on onshore gas exploration and production activities until 30 June 2020.

On 9 October 2017, the Victorian opposition announced an Onshore Gas Policy, which vows to maintain the ban on fracking but also commits to allow onshore conventional gas exploration and production in Victoria on a case-by-case basis, if the opposition is elected into government in 2018.[142]

The Victorian Gas Program

The Victorian Gas Program will investigate Victoria's gas potential and the issues surrounding gas exploration and development to help inform future decision-making of the Victorian government.[143] The three-year program will run until 2020, and is being funded $42.5 million by the Victorian government.

There are four main components to the program: 1) studies on the risks, benefits and impacts of conventional gas, 2) supporting offshore commercial exploration, 3) investigating potential for further underground gas storage in the Otway Basin, and 4) supporting onshore conventional gas and offshore gas work programs.[144]

The ACCC understands that some updates or progress reports are likely to be publicly released during 2018.

Onshore

Onshore unconventional gas potential

Recent assessments undertaken by GEOSCIENCE on the unconventional resource potential of the onshore Otway and Gippsland basins, suggest significant quantities of undiscovered, prospective gas in these areas.[145] There is estimated to be 7.6 trillion cubic feet (about 8018 PJ) of potentially recoverable tight and shale gas-in-place[146] in the onshore

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141 Department of Economic Development, Jobs, Transport, and Resources, *Onshore gas – community information*, http://onshoregas.vic.gov.au/

142 Liberal Victoria, *Liberal Nationals onshore gas policy*, https://vic.liberal.org.au/News/2017-10-09/liberal-nationals-onshore-gas-policy

143 Department of Economic Development, Jobs, Transport, and Resources, *Victorian Gas Program, http://earthresources.vic.gov.au/earth-resources/victorian-gas-program*

144 ibid.

145 Geoscience Australia, Interim Gippsland Basin unconventional resource assessment 2017, p. iii; Geoscience Australia, Interim Otway Basin unconventional resource assessment 2017, p. iii.

146 An estimated measure of the total quantity of gas contained in a reservoir.

Otway Basin, and 19.2 trillion cubic feet (about 20,257 PJ) of potentially recoverable tight and shale gas-in-place in the onshore Gippsland Basin. However, given the nature of these types of gas, significant uncertainty surrounds the magnitude of, and likely quantity of gas that will actually be recoverable from, these resources.

Lakes Oil

Lakes Oil is an example of a company that has been prevented from developing its onshore conventional and unconventional resources due to government restrictions. The company has been in a long-running legal dispute with the Victorian government since the introduction of the state's exploration ban in 2012. With permanent bans on fracking and extended moratorium, Lakes Oil has now turned its focus to conventional gas production.

According to Lakes Oil, independent expert advice suggests the total potential of its tenements is that summarised in the table below:[147]

Project	Estimated Gas Resource (50% probability)	Annual Production Potential
PRL 2: Wombat	250 PJ conventional out of 329 PJ, contingent	20 PJ
PRL 2: Trifon/Gangel	225 PJ conventional out of 390 PJ, contingent	
PEP 175 Focus Area: 'Portland Energy Project'	3000 PJ conventional out of 11,400 PJ, prospective	150 PJ
PEP 169: Otway-1 well	-	3-5 PJ

Lakes Oil exploration activity in the onshore Gippsland Basin has been focused on the Wombat gas field. If the production potential of the Wombat project is proven, Lakes Oil has indicated that it would be able to bring gas online within around 18 months and at a relatively low cost. Specifically, in a low case (90% confidence level) Lakes Oil estimates the wellhead gas price will be $7/GJ, in a central case (50% confidence level) it will be $6/GJ and in a high case (10% confidence level) it will be $5/GJ.[148]

In the Otway Basin, Lakes Oil efforts have been focused on the Otway gas field near Port Campbell. Lakes Oil's Otway-1 well will target conventional gas production from the Waarre Sandstone (which has historically produced gas) and the Eumeralla Formation. The Waarre Sandstone is said to flow gas at rates of up to 50 TJ/d.[149] Lakes Oil's Portland Energy Project which is also focused on acreage in the Otway Basin has the biggest gas potential, with estimates of annual production at a rate of 150 PJ per year.

On 11 October 2017, Lakes Oil announced that it had made a proposal to the Victorian government to overcome the issues which have prevented Lakes Oil engaging in onshore exploration.[150] The proposal seeks confirmation from the government that the company can test the existence of commercial quantities of conventional gas, and offers a commitment

[147] Lakes Oil, Fact Sheet, viewed 11 October 2017, http://www.lakesoil.com.au/index.php/reports-and-announcements/item/fact-sheet?category_id=14.

[148] Lakes Oil, Fact Sheet, viewed 11 October 2017, http://www.lakesoil.com.au/index.php/reports-and-announcements/item/fact-sheet?category_id=14.

[149] Lakes Oil, Onshore Otway Basin Victoria permits, viewed 6 December 2017, http://www.lakesoil.com.au/index.php/permits/onshore-otway-basin-vic .

[150] Lakes Oil, ASX Announcement: Proposal to Victorian Government, media release, 11 October 2017.

from Lakes Oil that gas recovered will be supplied and prioritised to Victorian consumers and industry.[151]

Offshore

Offshore South East Australia Future Gas Supply Study

On 24 November 2017, the Department of Industry, Innovation and Science released its findings on the Offshore South East Australia Future Gas Supply Study.[152] The report, which was prepared with contributions from the National Offshore Petroleum Titles Administrator, Geoscience Australia, and the Victorian, South Australian and Tasmanian governments, covers the Gippsland Basin, Otway Basin, the Bass Basin and the Sorell Basin.

The study found that there is an estimated 3.8 trillion standard cubic feet (about 4009 PJ) of known 2P gas resources and 3.7 trillion standard cubic feet (about 3904 PJ) of contingent resources (largely concentrated in the Gippsland Basin), which remain to be produced from offshore south east Australia. It also estimates 4.3 trillion standard cubic feet (about 4537 PJ) of prospective undiscovered quantities.

The study found that there are limited short-term gas prospects, with the major known gas fields reaching the end of their life and future production sources likely to backfill existing capacity rather than bring additional quantities of gas into the market. The study also found that infrastructure and technical constraints are likely to lead to long timeframes before remaining resources are able to be developed.

Based on titleholder forecasts, the study expects gas supply from offshore south east Australia to continue at current levels over the short-term, but declining over the medium term (the next 5-10 years). It cautions that an increase in gas supply from existing projects in the near term will result in faster depletion of reserves and will affect long-term security of supply. It notes that successful exploration and appraisal will be required to maintain current production levels over the longer term.

Manta (Gippsland Basin)

The Manta gas field located in the offshore Gippsland Basin has been assessed to contain over 620 PJ of contingent and prospective gas resources.153 Cooper Energy has said the case for development of the field has been advanced during the year by strong demand, agreement with APA to process gas at the Orbost Gas Plant and improved knowledge obtained through the adjacent Sole development project (which is expected to bring about 24 PJ per annum of gas to the market commencing in 2019).[154]

Current timing expectations for the Manta gas project are subject to the results of further exploration and appraisal.[155] If results prove positive, Cooper Energy has flagged the potential for drilling to commence as early as 2019, with potential production starting in 2022. The project is forecast to produce approximately 25 PJ in its first year of production.

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151 Lakes Oil, ASX Announcement: Proposal to Victorian Government, media release, 11 October 2017.

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

153 Cooper Energy, 2017 Annual Report, http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2017.10.16-2017-Annual-Report.pdf.

154 Cooper Energy, 2017 Annual Report, http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2017.10.16-2017-Annual-Report.pdf.

155 Cooper Energy, 2017 Annual Report, http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2017.10.16-2017-Annual-Report.pdf.

Dory (Gippsland Basin)

Earlier this year, Esso Australia acquired a large potential gas field on the edge of the continental shelf, called Dory, from Liberty Petroleum.[156] There have not yet been any commercial gas discoveries as the field is currently in exploration phase. Esso Australia has brought forward plans to commence exploration drilling of the field to mid-late next year, in response to growing concerns about an east coast gas shortage.[157]

While the type of gas present is not yet known, Liberty Petroleum has made claims that the field could contain up to 2.2 trillion cubic feet of gas (2,200 PJ).[158] According to Esso, if a commercial discovery of gas is found during exploration in 2018 (and depending on the size and quality of the discovery), production from the field could commence as early as 2024.

Halladale/Speculant/Black Watch (Otway Basin)

As noted in the September 2017 report, production from the Halladale/Speculant fields came online in August 2016.[159] Peak production is expected to reach 80 TJ/day but with a relatively short life of 6-8 years.[160]

Beach Energy, which takes over the development of these fields after its Lattice Energy deal (discussed further below), has indicated plans to drill an exploration well at the adjacent Black Watch field in FY20.[161]

South Australia

Historically, gas production in South Australia has predominantly been from conventional gas resources in the Cooper Basin. However, as conventional gas resources in the Cooper Basin continue to diminish, gas production is increasingly expected to come from unconventional gas resources.

In October 2016, the South Australian government launched its Plan for Accelerating Exploration (PACE) Gas Grants Scheme.[162] The scheme aims to accelerate the development of gas resources in South Australia in order to increase the state's supply of gas and improve energy reliability. Gas extracted through the scheme must first be offered to state electricity generators.

The government has already announced five grants under the scheme and is expected to announce a second round of successful grant proposals before the end of the year.[163]

While there are currently no bans on gas production in South Australia, the opposition has committed to introducing a 10 year moratorium on any exploration or development of unconventional gas in the Limestone Coast area in the state's South East, if elected in 2018.[164]

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156 The Australian (Matt Chambers), ExxonMobil lands a whopper in Bass Strait with huge gas reserves, 7 August 2017.

157 ibid.

158 ibid.

159 Origin media release, 'Halladale/Speculant comes online', https://www.originenergy.com.au/about/investors-media/media-centre/halladale-speculant-comes-online.html

160 EnergyQuest, *EnergyQuarterly - December 2017*, p. 68.

161 ibid, p. 69.

162 South Australia Department of the Premier and Cabinet, *PACE Gas,* viewed 6 December 2017, http://petroleum.statedevelopment.sa.gov.au/latest_updates/pace_gas.

163 South Australia Department of the Premier and Cabinet, Gas grants and new exploration area to boost local supply, media release, 17 March 2017.

164 Steven Marshall, Fracking – a 10 year moratorium for the limestone coast, media release, http://www.stevenmarshall.com.au/fracking.

The Vanessa Gas Project (Cooper Basin)

Senex and Beach Energy have accelerated development of the conventional Vanessa gas field in the northern Cooper Basin, which is expected to come online in the second half of 2018.[165] However, total quantities of gas expected to be available in the short term are unlikely to be material. The Vanessa gas project was the recipient of a $5.82 million grant through the PACE scheme in March 2017.

Strike Energy (Cooper Basin)

Oil and gas company, Strike Energy, is the operator of the Southern Cooper Basin Gas Project in South Australia. In March 2017, Strike Energy received $2 million worth of funding for the first phase of its deep coal project through the South Australian PACE gas grants scheme.

Strike is currently undertaking appraisal and development work on the project, recently announcing technical success and production capability of the Vu Upper coal seam in the Klebb area.[166] The Vu Upper coal seam is estimated to have a gas content of up to 6 cubic metres per tonne.

While this is a positive development, it is important to note that Strike Energy has been working on developing gas from the Southern Cooper Basin Gas Project for a number of years, illustrating the uncertainty and risk involved in upstream gas production.

Beach Energy

Beach Energy has also secured funding through the PACE scheme, receiving a grant of $6 million towards exploration in the Otway Basin targeting conventional reservoirs.

On 28 September 2017, Beach Energy announced an agreement with Origin Energy to purchase its upstream Lattice Energy division.[167] The deal is will significantly expand Beach Energy's current gas portfolio, with Beach Energy expected to acquire assets (or additional assets) in the Bonaparte, Perth, Otway, Bass, Canterbury, Taranaki and Cooper basins.[168]

The proposed $1,585 million transaction is expected to increase Beach's 2P reserves by about 200% to 232MMboe, and increase its FY18 production to 25-27 MMboe or 152–165 PJ (around 150%).[169]
The transaction is currently pending approval from the New Zealand Overseas Investment Office and the New Zealand Minister of Energy and Resources.[170]

Hydrogen technology to support gas supplies

On 8 August 2017, the Federal Minister for the Environment and Energy announced a new project to be trialled in South Australia to test whether excess renewable energy can be used

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165 Senex Energy Limited, September 2017 Quarterly Report, https://www.senexenergy.com.au/wp-content/uploads/2017/10/2017.10.25-September-2017-Quarterly-Report.pdf.

166 Strike Energy, Quarterly Activities Report Q3 2017.

167 Beach Energy, ASX announcement: Beach Energy announces transformational acquisition of lattice energy and a $301 million 3 for 14 pro-rata entitlement offer, 28 September 2017, http://www.beachenergy.com.au/irm/PDF/6814_0/LatticeEnergyacquisition.

168 Beach Energy, 2017 Annual Report, http://www.beachenergy.com.au/irm/PDF/6784_0/2017BeachEnergyLtdAnnualReport, pp. 8-9.

169 Ibid.

170 Ibid.

to produce cheap hydrogen gas for injection into the South Australian gas grid.[171] The project is to be run by AquaHydrex and has been granted $5 million worth of funding from the federal government through the Australian Renewable Energy Agency.

Santos' Cooper Basin activity

On 9 November 2017, Santos announced increased drilling plans for the Cooper Basin to grow production and increase gas supply for the domestic market.[172] Santos plans to drill 70-80 wells (including exploration wells) in the Cooper Basin during 2018 – an increase from about 60 wells in 2017.[173]

Santos also emphasised its renewed focus on Cooper Basin exploration and the potential for the Cooper Basin to generate new gas reserves.[174] In particular, Santos mentions that appraisal drilling has proved that the 2,000 acre Namur gas field is a significant resource and indicates appraisal of the Corrikiana reservoirs could provide further gas resource potential.[175]

New South Wales

New South Wales proclaims to have 'the toughest coal seam gas regulations in Australia'.[176] These are set out in the NSW Gas Plan, which is based on the 2014 findings of the Chief Scientist and Engineer's Independent Review of CSG Activities in New South Wales.

In New South Wales there is a ban on BTEX[177] chemicals used in coal seam gas drilling and fracking, as well as bans on coal seam gas exploration and production activity within 2km of existing and future residential areas.[178] There are regulations that govern mining and coal seam activity, codes of practice on coal seam gas exploration and substantial regulatory oversight.

As part of its Gas Plan, the NSW government has engaged in a buyback program of petroleum exploration licenses.[179] The scheme provided the opportunity for holders of these licenses to surrender their titles in exchange for limited compensation. A total of 17 licenses have been surrendered under the scheme.[180]

The only currently producing area in NSW, Camden, is set to finish production in 2023.[181] With gas from the Cooper Basin largely committed to Queensland, NSW receives less gas from the Cooper Basin than it had in the past. As a result of the state's regulatory restrictions, NSW is increasingly reliant on gas from offshore Victoria or purchasing gas from the Queensland producers.

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171 The Hon. Josh Frydenberg MP (Minister for the Environment and Energy, Testing new hydrogen technology for energy storage, media release, 8 August 2017.

172 Santos, 2017 Investor Day presentation.

173 EnergyQuest, *EnergyQuarterly - December 2017*, p. 67.

174 Santos, 2017 Investor Day presentation, p.39.

175 ibid, p.40.

176 Department of planning and the environment (NSW), Coal seam gas, viewed 6 December 2017, http://www.planning.nsw.gov.au/Policy-and-Legislation/Mining-and-Resources/Coal-Seam-Gas.

177 Benzene, Toluene, Ethylbenzene and Xylene.

178 Department of planning and the environment (NSW), Coal seam gas, viewed 6 December 2017, http://www.planning.nsw.gov.au/Policy-and-Legislation/Mining-and-Resources/Coal-Seam-Gas.

179 Department of planning and the environment (NSW), FAQs on coal seam gas, viewed 6 December 2017, https://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0005/534830/NSW-Gas-Plan.pdf

180 Department of planning and the environment (NSW), PEL buy-back, viewed 6 December 2017, https://www.resourcesandenergy.nsw.gov.au/landholders-and-community/coal-seam-gas/information-on-petroleum-titles/buy-back

181 AGL, Camden gas project, viewed 6 December 2017, https://www.agl.com.au/about-agl/how-we-source-energy/natural-gas/natural-gas-projects/camden-gas-project/about-the-project.

On 6 June 2017, the NSW government announced the implementation of the Strategic Release Framework under its Gas Plan designed to ensure future gas exploration is in accordance with the State's terms and can be done safely and appropriately.[182] The NSW government has said that with all actions of the Gas Plan complete, it is "able to consider on a case-by-case basis the responsible development of the gas industry in NSW".[183]

Narrabri (Gunnedah Basin)

The Santos-operated Narrabri project in the Gunnedah Basin is estimated to produce 70 PJ a year once production commences, offering a significant amount of relief to the supply issues being faced by the east coast gas market.[184] However, timing of production remains uncertain, with the coal seam gas development continuing to face regulatory delays related to the state's approval process.

It worth noting that over the past two years Santos has written down the value of the Narrabri project to zero.[185] However, in a recent announcement made on 9 November 2017, Santos has re-added the gas asset to the company's core project list.[186]

Commonwealth

The gas industry has been a priority for the Commonwealth government, which has been active in its effort to encourage accelerated gas development.

The 2017/18 Federal Budget included $86.3 million dollars of funding to be provided over four years from 2017-18 towards measures to increase gas production, as well as to support affordable electricity prices for households and industry.[187]

Gas Acceleration Program

The Department of Industry, Innovation and Science is currently developing a Gas Acceleration Program focused on accelerating development of known significant gas resources.[188]

The $26 million dollar program will target projects with the greatest likelihood of bringing new gas online from onshore gas fields and delivering gas to east coast gas consumers within three years.

Retention Leases

The National Offshore Petroleum Titles Administrator (NOPTA) administers the title scheme relating to the grant of retention leases in Commonwealth waters in Australia.[189]

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182 Don Harwin (NSW Minister for Resources, Energy and Utilities and for the Arts, Strategic conventional gas exploration sites identified in Western NSW, media release, 6 June 2017.

183 ibid.

184 Santos, Referral of proposed action: Narrabri, https://www.santos.com/media/1932/narrabri-gas-project-epbc-referral-final.pdf.

185 Australian Financial Review, The $3.6b Santos project that came in from the cold, 19 September 2017, http://www.afr.com/business/the-36bn-santos-project-that-came-in-from-the-cold-20170919-gykl34.

186 Santos, 2017 Investor Day presentation, media release, 9 November 2017, https://www.santos.com/media-centre/announcements/2017-investor-day-presentation/.

187 Budget 2017-18, Budget Measures: Budget Paper No.2, http://www.budget.gov.au/2017-18/content/bp2/download/bp2.pdf, p.95.

188 Department of Industry, Innovation and Science, Gas Acceleration Program, viewed 6 December 2017, https://industry.gov.au/resource/Programs/Pages/Gas-Acceleration-Program.aspx.

189 National Offshore Petroleum Titles Administrator, Petroleum retention lease, viewed 6 December 2017, http://www.nopta.gov.au/application-processes/development/petroleum-retention-lease.html.

Retention leases provide security of title for those resources that are not currently viable but are likely to become so within 15 years.

The objective of a retention licence is 'to ensure a lessee addresses the barriers to the commercial development of petroleum resources and, where it is commercially viable to do so, bring those resources to production in a timely manner'.[190] NOPTA is responsible for monitoring a lessee's compliance with their work program.

Retention leases have a term of five years but are capable of renewal.

[190] Department of Industry, Innovation and Science, Guideline – Grant and Administration of a retention lease, October 2016, http://www.nopta.gov.au/_documents/guidelines/RL-Guideline.pdf, p. 3.

6. LNG markets and netback price series

6.1. Key points

- The ACCC is considering the possibility of developing and regularly publishing on its website throughout this inquiry an LNG netback price series at Wallumbilla to enhance transparency of gas prices in the East Coast Gas Market.
- Global LNG markets have developed over the past several decades based on long-term sales agreements. Asian countries have dominated both historic demand and contemporary growth in demand.
- LNG spot markets are rapidly evolving and there has been a significant growth in the proportion of international LNG trade taking the form of short-term contracts and spot sales in recent years. Prices in the LNG spot markets are volatile but may moderate as the market matures.
- Future LNG supply growth is expected to be strong, however there is uncertainty with respect to demand over the medium-term.
- The crude oil price is not a perfect proxy for LNG prices but will remain a key pricing instrument until a robust LNG price index is developed.
- For the purposes of a potential LNG netback price series, the ACCC is at this stage assessing options for information sources on Asian LNG spot prices, which the ACCC considers is the most relevant LNG price for the purposes of an LNG netback price at Wallumbilla.
- Further, the ACCC is considering the methodology that would be used to derive an LNG netback price. This methodology would involve taking a measure of Asian LNG spot prices and deducting relevant costs (in particular, shipping and liquefaction costs) to derive a netback price that would be comparable to domestic prices at Wallumbilla.
- The ACCC is also considering extending the LNG netback price series into the future using market expectations of future Asian LNG spot prices. This would involve taking a measure of expected Asian LNG spot prices (such as futures market quotes) and making similar deductions for shipping and liquefaction costs as for a current netback price.
- The ACCC will, in coming months, consult with gas market participants and seek views on the desirability of an LNG netback price series and the approach outlined in this section. With this report we are commencing this consultation process and seeking views of interested parties.

6.2. LNG markets

6.2.1. History

International trade in LNG emerged in the 1960s with exports from Algeria to the UK and France.[191] By the early 1970s Libya was exporting to Spain and Italy while the US and Brunei were exporting to Japan. Indonesia and Abu Dhabi joined the list of exporting countries in the late 1970s. Annual global LNG trade quantities reached 25 million tonnes (MTPA) in 1979, with more than half destined for Japan.[192]

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[191] British Chamber of Commerce Singapore, *LNG 50: A Celebration of the First Commercial Shipment of LNG*, September 2014, http://www.britcham.org.sg/files/event_document/6/6LNG%20A5%20Booklet-FINAL.compressed.pdf.

[192] Ibid.

Buyers were typically major gas powered electricity generators and gas utilities, whose level and consistency of demand allowed them to commit to long-term sales agreements. These long-term agreements underpinned the investment required by exporters to develop LNG export projects.

Malaysia and Australia began exporting in the 1980s, with trade quantity rising to 48 MTPA in 1989.[193] Japan was the recipient of much of this increase in quantity, consuming two-thirds of global imports in 1989. The 1990s and 2000s saw more rapid diversification in sources of supply, with the list of exporters expanding to eighteen countries by 2010. The quantity of LNG traded internationally increased to 100 MTPA in 2000 and to 193 MTPA in 2010. Although Japan remained the largest importer, its share of global imports fell to around one-third in 2010. This reflected a diversification in sources of demand, with Korea, India and China in particular having emerged as major importers.[194]

Total internationally traded quantities reached 264 MTPA in 2016.[195] Qatar accounted for 30 per cent of exports, having grown rapidly since entering the market in the 1990s. Australia's share of exports increased to 17 per cent, up from 9 per cent in 2006. A total of 39 countries imported LNG in 2016, with Asian countries accounting for 73 per cent of demand.[196]

Chart 6.1: LNG export shares 2016

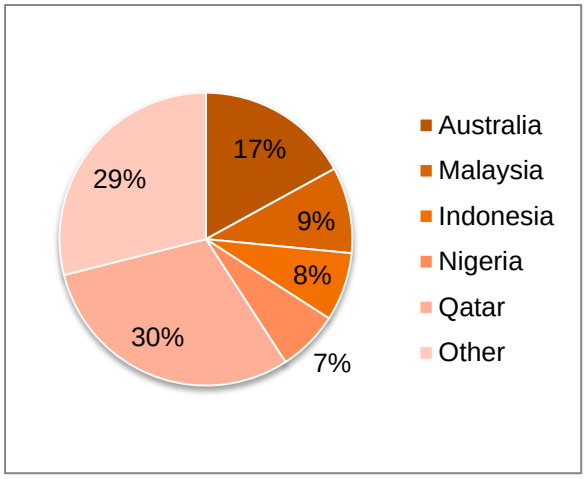
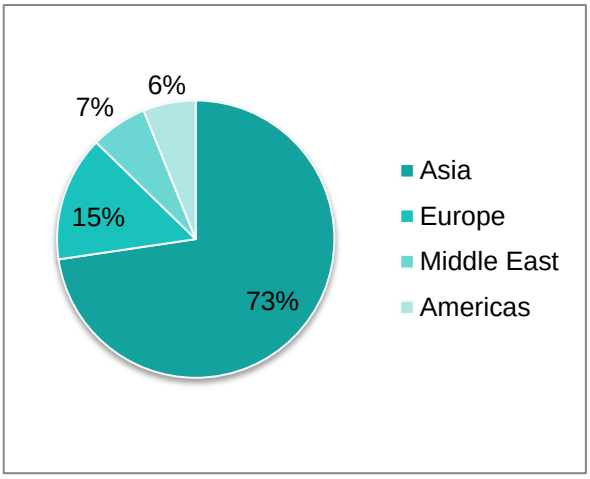


Chart 6.2: LNG import shares 2016



Source: GIIGNL, *Annual Report 2017*

LNG pricing

International LNG sales contracts have historically used pricing mechanisms that tie LNG prices to oil prices. There are a number of reasons for this. Oil-linked pricing allows parties to enter long term bilateral contracts yet retain price flexibility to allow for changes in market conditions over the term of the contract. Oil and gas were in the past somewhat substitutable as the two fuels competed for power generation. In addition, the maturity of the oil markets allows gas market participants to access financial instruments to manage risk that are not as

193 British Chamber of Commerce Singapore, *LNG 50: A Celebration of the First Commercial Shipment of LNG*, September 2014, http://www.britcham.org.sg/files/event_document/6/6LNG%20A5%20Booklet-FINAL.compressed.pdf.

194 Ibid.

195 International Group of Liquefied Natural Gas Importers, *2017 Annual Report* and *2006 Annual Report,* http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2017_annual_report_0.pdf, http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_the_lng_industry_2006.pdf.

196 Ibid.

readily available in LNG markets. Natural gas is also a by-product of oil production so the price of gas may be influenced by long-term cyclical trends in the oil market.

In the LNG spot market, prices are set directly by over-the-counter trades using a tender process rather than via oil linkages. The spot price is therefore more reflective of the LNG market's supply and demand fundamentals. LNG spot prices have at times even moved in the opposite direction to oil prices. Regional variation in LNG spot prices has also emerged, reflecting regionalised supply and demand conditions.[197] With a growing proportion of LNG trade shifting to the short-term and spot markets (see 'Trade' section below), the overall influence of oil prices on LNG prices may weaken over time.

Trade

The vast majority of international trade in LNG has historically been under long-term contracts. Producers have sought long-term sales commitments to back the large investment required to develop LNG projects, while buyers have been willing to commit to long term contracts in order to secure certainty of supply.[198] Recent years have seen a growing proportion of international LNG trade taking the form of short-term contracts and spot sales[199]. In 2016, 28 per cent of LNG traded internationally was sold under short-term or spot contracts,[200] up from around 5 per cent in 2000.[201]

The trend toward a greater proportion of trade coming under short-term and spot contracts is reflective of a more liquid market and a supply-demand balance tipping in favour of buyers[202]:

- Increasing diversity of supply sources tends to boost the likelihood that a buyer will be able to find suitable supply of LNG on a short-term or spot basis. This may reduce the impetus for some buyers to secure supply under long-term contracts. Notably, in 2016 exports began shipping from the contiguous US for the first time and have included spot sales into Asia.[203]
- Growing global supply at the same time as softening demand from Asia[204] increases the likelihood that excess LNG – beyond that required to fulfil projects' long-term contract obligations – is made available for sale into short-term contracts or the spot market.
- Destination clauses that prevent buyers under long-term contracts re-selling cargoes to third parties appear to be on the decline.[205] In 2017, Japan's Fair Trade Commission recommended that new LNG import contracts exclude the clauses.[206] Europe, having

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197 See, eg, oilprice.com, *The Coming Revolution, September 2016,* https://oilprice.com/Energy/Natural-Gas/The-Coming-Revolution-in-LNG-Pricing.html.

198 See, eg, OCP Policy Center, *The development of the liquefied natural gas spot market: origin and implications*, January 2016, http://www.ocppc.ma/publications/development-liquefied-natural-gas-spot-market-origin-and-implications#.Wd7O6bu7qUk.

199 Short term sales are defined as contract agreements of less than 4 years duration.

200 International Group of Liquefied Natural Gas Importers, *2017 Annual Report*, p. 2, http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2017_annual_report_0.pdf.

201 US Energy Information Administration, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region,* March 2017, p. 30, https://www.eia.gov/analysis/studies/lng/asia/pdf/lngasia.pdf, citing International Group of Liquefied Natural Gas Importers.

202 See, eg, US Energy Information Administration, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region,* March 2017, p. 7-8, https://www.eia.gov/analysis/studies/lng/asia/pdf/lngasia.pdf.

203 Forbes, *U.S. Liquefied Natural Gas To China Is A Game-Changer*, May 2017, https://www.forbes.com/sites/judeclemente/2017/05/25/u-s-liquefied-natural-gas-to-china-is-a-game-changer/#34599a87671a.

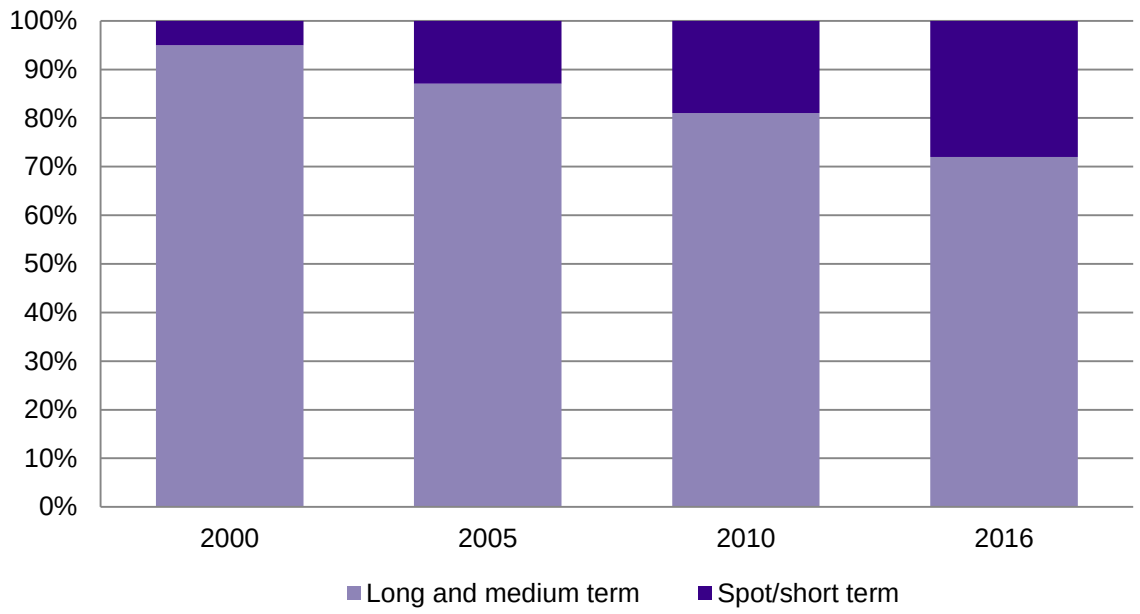
204 Ibid.

205 See, eg, US Energy Information Administration, *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region,* March 2017, p. 31, https://www.eia.gov/analysis/studies/lng/asia/pdf/lngasia.pdf.

206 See, eg, Australian Financial Review, *LNG Power Shift Moves Further in Favour of Buyers*, July 2017, http://www.afr.com/business/energy/gas/lng-power-shift-moves-further-in-favour-of-buyers-20170703-gx3c5m.

made a similar move a decade ago, saw 9 per cent of its imports re-exported in 2016, compared with virtually non-existent re-exporting activity from Asian countries.[207] This suggests scope for a substantial increase in short-term and spot market activity driven by emergent re-selling activity of buyers in Asia. Indicative of the trend toward greater flexibility for buyers, US exporter Cheniere appears to have adopted as a selling point the fact that its contracts do not include restrictions on re-selling.[208]

Chart 6.3: Global LNG trade: Spot/short term as a proportion of total trade



Source: GIIGNL annual reports; EIA, Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region

6.2.2. Contemporary issues/trends in the LNG market and relevance to the domestic market

Uncertainty in spot markets

LNG prices have historically been volatile. Chart 6.4 shows that Northeast Asian spot LNG prices are more variable than Brent crude oil prices. Based on the monthly standard deviation over the past five years, the Australian dollar LNG price is approximately twice as volatile as the Australian dollar Brent crude oil price.

Commodities like crude oil and LNG are priced in US dollars. Uncertainty about the future Australian dollar price of the commodity is due to two factors. Either the price of the commodity may change for reasons of supply and demand or the Australian dollar may appreciate/depreciate against the US dollar.

The LNG price is inherently more variable than the oil price. Exchange rate volatility adds an additional increment of uncertainty to the LNG price when quoted in Australian dollar terms. The oil price behaves differently to the LNG price as it is less variable and varies to about the same degree regardless of whether it is denominated in US dollars or Australia dollars. If

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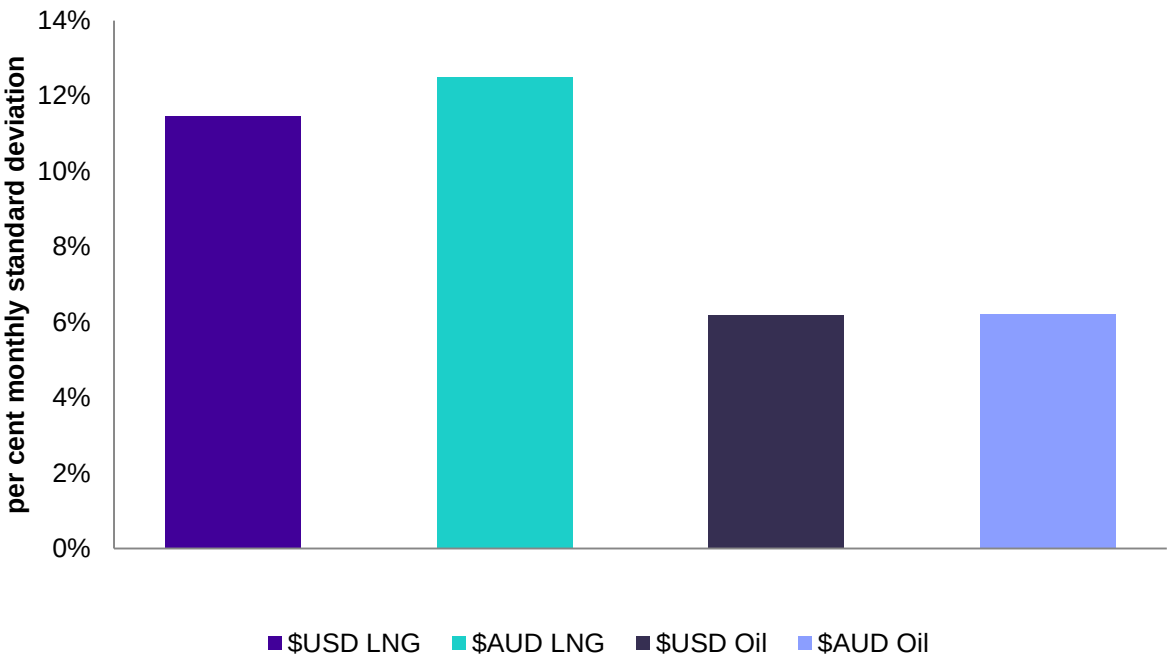
207 International Group of Liquefied Natural Gas Importers, *2017 Annual Report*, p. 19, http://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2017_report_2.pdf.

208 Reuters, *Qatar crisis to speed the rise of Asia's spot LNG trade*, June 2017, https://www.reuters.com/article/us-qatar-asia-lng-analysis/qatar-crisis-to-speed-the-rise-of-asias-spot-lng-trade-idUSKBN1930W9.

the oil price increases in value the Australian dollar will also tend to increase in value. This relationship moderates the movement of Australian dollar denominated oil price.[209]

Chart 6.4: Monthly volatility of north East Asian spot LNG and Brent crude oil prices



Source: Internal ACCC analysis, Europe Brent Spot Price FOB (eia) and ANEA LNG spot price (Argus Media Limited)

The potential for future LNG prices to vary poses both risks and opportunities to LNG producers as well as domestic gas producers and gas buyers. LNG producers invest in production based on their expectations of the profitability of supplying the LNG market. The revenue LNG producers will earn from those investments is uncertain as oil price movements affect the revenue earned from oil-linked LNG contracts and LNG price movements affect the revenue earned from spot sales. Pricing formulae for LNG sales under oil-linked contracts are often structured to reduce the effect on the contract price of very large movements in the oil price. This structure yields a price distribution that is commonly known as an S-curve.[210]

Gas buyers can insulate themselves from future price rises by contracting to buy gas over the long-term at a fixed price but may also prefer a floating price linked to international markets. Gas buyers forgo the possibility of a lower price in the future by committing themselves to buy gas under a long-term GSA that are based on fixed prices.

A gas buyer's ability to minimise the risks and maximise the benefits of movements in the international LNG market depends on the level of flexibility afforded under their GSA. For example, during periods when LNG prices are high a domestic gas buyer may seek to on-sell contracted gas to an LNG producer (provided that there are no on-selling restrictions in the GSA). Alternatively, when LNG markets are weak a domestic gas buyer may seek to

[209] The oil price and the Australian dollar can move against each other and have done so in the past

[210] ACCC, *Inquiry into the east coast gas market*, April 2016, p. 33.

obtain supply under short-term agreements from an LNG producer whilst reducing the quantity of gas they take under their long-term GSAs.

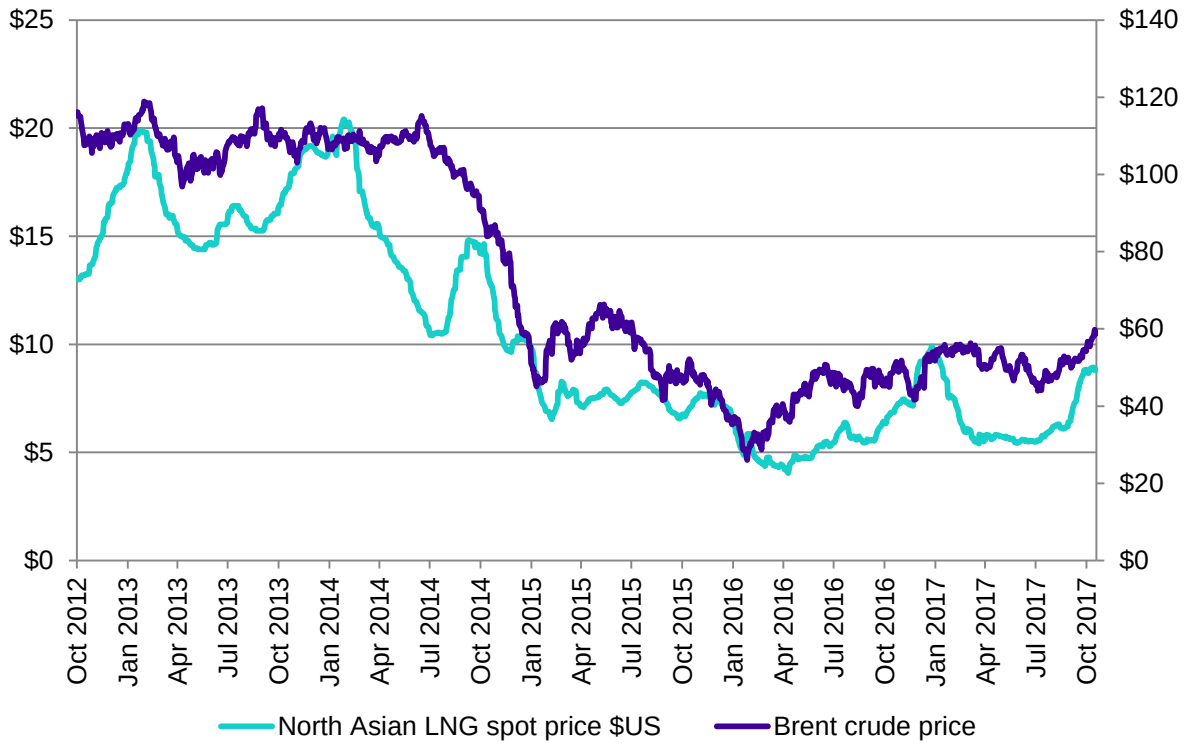
A gas buyer may prefer a floating price linked to international gas prices as they may view such pricing as more transparent or they may expect prices to decrease in the future. In the case where the gas buyer's enterprise is also exposed to international markets, a floating price may be aligned more closely with the gas buyer's revenues than a fixed price.

LNG price volatility may reduce over time as markets for LNG become deeper and more liquid. Market participants may be able to use financial instruments and physical storage to smooth price movements. For example, if the future price of LNG is high a market participant might buy and store physical gas in the present and enter into a contract to supply that gas in the future. However, as it is a gas rather than a liquid (except at a very low temperature) the LNG price is always likely to be more volatile than the oil price as it is inherently more difficult to store and transport.

Crude oil linkage

The majority of LNG exports are directly linked to crude oil prices by pricing formula under long-term contracts. Chart 6.5 shows that LNG spot prices tend to broadly move in the same direction as crude oil prices. The chart also shows that LNG spot price movements can deviate from crude oil price movements and that LNG spot prices are more affected by seasonal variation than crude oil prices.

Chart 6.5: Comparison Brent crude oil price and LNG spot price



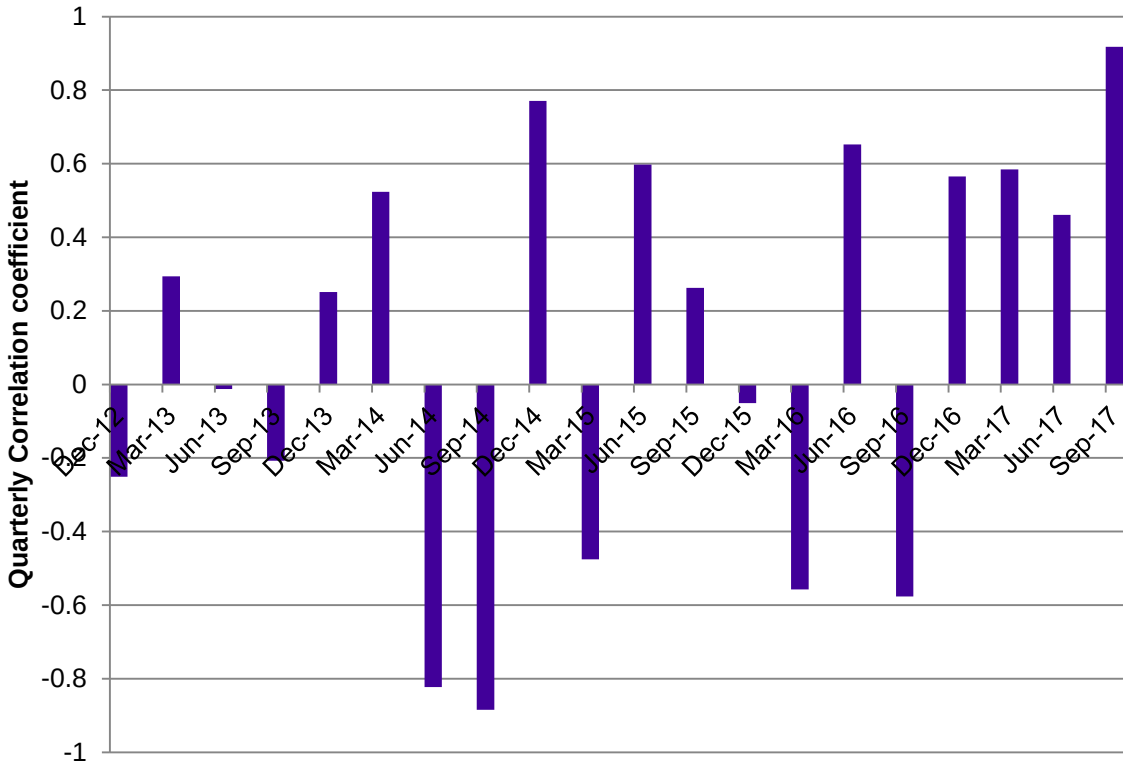
Source: Europe Brent Spot Price FOB (eia) and ANEA LNG spot price (Argus Media Limited)

The LNG spot prices and crude oil prices may become less correlated as the LNG spot market matures and becomes more independent of oil markets. However, the timing of this and, in fact, whether or not it has already occurred, is uncertain.

Chart 6.6 shows that over short periods (3-months) the LNG spot price moves in a similar direction to the crude oil price more often than not. Over the past five years, there have been

periods when the LNG spot price has moved with the oil price and periods where the LNG spot price has moved against the oil price. In the middle of 2014, the LNG spot price increased while the crude oil price fell precipitously. More recently, the two prices have moved in similar directions. Overall, oil prices are at best an unreliable indicator of LNG spot prices. However, until a robust LNG spot price index emerges, oil-linked contracts are likely to continue to be used to price long-term LNG contracts.

6.6: Quarterly correlation between Brent crude oil price and north-east Asian LNG spot price



Source: Internal ACCC analysis, Europe Brent Spot Price FOB (eia) and ANEA LNG spot price (Argus Media Limited)

Future demand in key international markets

Japan, South Korea, China and India are the four largest importers of LNG in the world.[211] The four countries are key destinations for Australian LNG exports and their markets are affected by the unique dynamics of each nation's economy, energy sector and politics.

Japan

In 2011, Japan shut down most of its nuclear power plants following the Fukushima Daiichi nuclear disaster. The need to replace energy previously generated by nuclear power plants led to a 26 per cent increase in Japanese imports of LNG over the subsequent four years. This was followed by a decline in imports of 6.2 per cent for the year 2015 and then a modest increase in 2016. Japanese LNG imports are expected to continue to decline gradually in 2017 and 2018 but the extent to which reactors are restarted will be a factor in the quantity of LNG imported by Japan.[212] If nuclear generation is brought back online it will

[211] U.S. Energy Information Administration, Today in energy, viewed 7 December 2017, https://www.eia.gov/todayinenergy/detail.php?id=27652

[212] The Institute of Energy Economics, Japan, A Japanese Perspective on the International Energy Landscape, 10 August 2017, https://eneken.ieej.or.jp/data/7494.pdf

displace gas powered generation fuelled using LNG imports. The sum of the generation capacity of nuclear units that have been suspended or are shut down for maintenance (not scheduled for decommissioning or in cold shutdown) is 33 gigawatts. If all of these units were brought back online, Japanese LNG requirements for energy generation would reduce in the order of 1000 PJ per annum.[213]

Korea

Like Japan, South Korea has a modern developed economy with a mature energy sector reliant on LNG imports. However, South Korea's nuclear generation has not had to be shut down so its LNG demand has been more stable. South Korea's LNG demand fluctuates due to normal variation in its economy and weather. Natural gas consumption fell from a peak of 47.3 million tonnes oil equivalent in 2013 to 39.3 million tonnes oil equivalent in 2015 and then slightly increased 3.7 per cent to 40.9 million tonnes oil equivalent in 2016.[214]

Over the longer term South Korean LNG demand may be influenced by future policies limiting the use of nuclear or coal power generation.

China

There is potential for growth in LNG demand in China due to a range of factors. China's growing economy requires energy from all sources. China is also seeking to reduce pollution in its major cities by switching generation to energy sources like natural gas that do not produce the quantities of particulates associated with coal fired generation.[215] China may also wish to maintain a diversity of energy sources for strategic reasons. Chinese LNG consumption increased by 7.7 per cent or 16 billion cubic meters in 2016 which accounts for roughly one quarter of the total global increase in natural gas usage.[216]

Chinese demand for natural gas can also be satisfied by overland shipments, which are an alternative to LNG imports. The Russian energy giant Gazprom is building the Power of Siberia pipeline to supply gas to China. The pipeline has the capacity to transport in the order of 38 billion cubic meters per year of natural gas yearly from the Yakutia and Irkutsk regions of Russia. Gas supplies are scheduled to start in December 2019 under a 30-year agreement negotiated with the Chinese government.[217] The extent to which natural gas from Russia will displace existing LNG imports will depend on whether growth in the Chinese economy and concomitant demand for energy are sustained.

India

There is potential for significant increases in LNG demand to come from India. As with China, Indian LNG demand is increasing with the overall demand for energy and is seen as part of the solution to reducing pollution. Domestic gas production in India is expected to grow at 3 per cent annually while demand is expected to grow at 7 per cent.[218] Domestic gas production is also increasingly allocated away from industry towards residential and transport use.[219] Indian LNG imports have increased nearly 10 fold from approximately 2 million tonnes of LNG in 2004 to 19 million tonnes in 2016 and are expected to surpass 30

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213 Internal ACCC analysis.

214 BP Statistical review of World Energy 2017

215 Ibid.

216 Ibid.

217 Gazprom website, Power of Siberia, 14 November 2017, http://www.gazprom.com/about/production/projects/pipelines/built/ykv/

218 Platts, India natural gas: A 5-year outlook on supply and demand, 22 June 2017, https://www.platts.com/videos/2017/june/snapshot-india-lng-outlook-062217

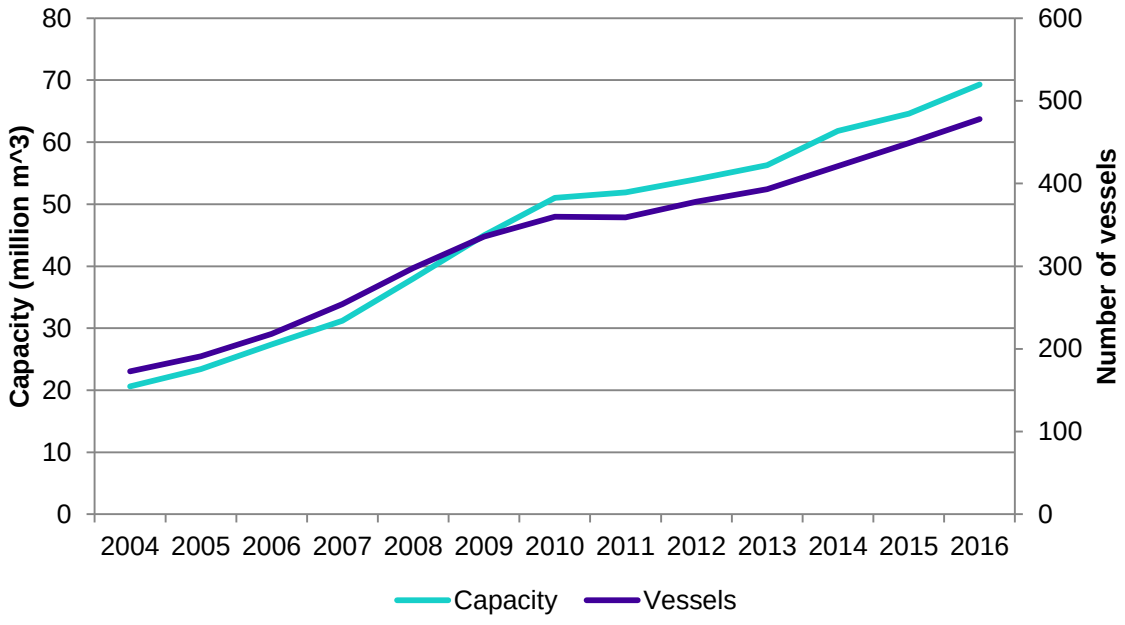
219 The Hindu, Gas allocation to be rejigged, 3 August 2017, http://www.thehindu.com/business/Economy/gas-allocation-to-be-rejigged/article6186020.ece

million tonnes by 2020. Unlike China, India's neighbours are net importers of gas leaving LNG as a likely option to fulfil the increasing demand for gas.

Supply

Globally the supply of LNG stood at 346.6 billion cubic metres in 2016 and will continue to increase. LNG production capacity is expected to be 30 per cent above 2016 levels by 2020.[220]

Chart 6.7: LNG shipping capacity



Source: GIIGNL annual reports

A key indicator of growth in LNG markets is the steady increase in shipping capacity. Shipping capacity grew by 136 per cent over the period from 2004 to 2016 to 69.3 million cubic meters or the equivalent of approximately 31 million tonnes. The total tonnage of LNG ships is, however, still small compared to that of oil tankers, which stood at 535 million tonnes in 2017.[221]

LNG tankers have also grown larger with the average ship being able to carry 3.7 PJ, representing a 22 per cent increase in capacity since 2004. Growth in ship size is likely to be limited by what sizes can be accommodated at LNG terminals. At present the Q-MAX type LNG tankers, which can carry 6.8 PJ of LNG, are the largest LNG tankers in the world and is the maximum size of a ship able to dock at LNG terminals in Qatar.

6.3. LNG netback price series

In the ACCC's 2015 inquiry, the ACCC discussed the influence that LNG netback prices were likely to have on the outcomes of gas supply negotiations in the domestic market.[222] The ACCC observed, however, that there appeared to be little common understanding of

[220] BP Statistical Review of World Energy 2017

[221] United nations conference on trade and development, merchant fleet by flag of registration and by type of ship, annual, 1980–2017, viewed on 7 November 2017, http://unctadstat.unctad.org/wds

[222] ACCC, *Inquiry into the east coast gas market*, pp. 42-53.

what an LNG netback price means for domestic gas market participants, how it is calculated, and how it should be reflected in the domestic market.[223]

To address this, and to enhance transparency of gas prices, the ACCC recommended that AEMO develop and publish a monthly LNG netback price to Wallumbilla, with an explanation of the framework and of relevant inputs.[224]

During the current inquiry, gas users have expressed interest in a regular ACCC-published LNG netback price to enhance transparency and provide greater information and bargaining power to users in negotiations with gas suppliers.

In light of the ACCC's previous recommendation and current user interest, the ACCC is considering the possibility of publishing, throughout this inquiry, an LNG netback price series at Wallumbilla. Such an LNG netback price series would extend back to the beginning of 2016 and potentially forward to the end of the subsequent calendar year. The LNG series would be published as a chart on the ACCC's website and updated by the ACCC on a regular basis over the course of the inquiry.

Further, the publication would include explanatory material which would set out, step-by-step, how an LNG netback price is calculated. However, depending on the source of LNG price used in the netback price calculation, the publication may include only the final LNG netback price without the individual components (discussed further below).

This section discusses the LNG netback price methodology being considered by the ACCC and the information on which the LNG netback price series could be based. The ACCC will, in coming months, consult with gas market participants to seek views on the desirability of an LNG netback price series and the approach outlined below.

6.3.1. LNG netback price methodology

To calculate a LNG netback price series, the ACCC would use the methodology set out in the September 2017 report. Specifically, the ACCC would take a relevant delivered LNG price (usually expressed in US$/MMBtu), convert it into AU$/GJ and subtract the costs of shipping and liquefaction to arrive at an LNG netback price at Wallumbilla. The methodology and sources for the various components that would make up an LNG netback price calculation are set out below.

LNG price

The starting point for calculating an LNG netback price at any given time is an LNG price. While the ACCC could publish an LNG netback price series based on a measure of either LNG spot prices or prices under long-term LNG contracts, the ACCC considers that an LNG netback price series based on LNG spot prices would be of most use to the domestic gas buyers.

As discussed in section 1, the east coast LNG exporters expect to have sufficient gas to meet their contractual export commitments in the short-term and have additional gas that could be sold into LNG spot markets. In these circumstances, domestic buyers would have to be prepared to pay a price that is at least equivalent to the LNG spot netback price to compensate suppliers for the opportunity cost of exporting the gas on the LNG spot market. Therefore, the price that can be achieved by LNG producers on LNG spot markets would be expected to influence domestic price negotiations.

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[223] ACCC, *Inquiry into the east coast gas market*, p. 89.

[224] ACCC, *Inquiry into the east coast gas market*, p. 89.

The ACCC acknowledges, however, that circumstances may arise in which an LNG netback price based on prices under long-term contracts becomes more relevant–for example, if the LNG exporters do not have sufficient gas supply to meet contractual export commitments.

The ACCC has further considered which LNG spot markets are relevant. As noted in section 3.2.1, short-term LNG trades as a proportion of total global LNG trades have increased significantly over recent years. The Asian market is likely to be the largest spot trading market by volume. This, coupled with the relative proximity of the Queensland LNG producers' facilities to Asian LNG ports, makes the Asian LNG spot market the primary alternative for the east coast LNG producers when deciding whether to sell excess gas domestically or for export. The ACCC has observed that LNG spot sales by the east coast exporters to date have typically been to Asian buyers. In addition, the ACCC has observed in the supplier's board documents that the Asian LNG spot prices have been the primary point of comparison in circumstances where those suppliers have compared the value of selling gas domestically and for export.

Therefore, the ACCC considers that an LNG netback price series should be based on a measure of Asian LNG spot prices. Further, so that this measure of prices is as representative as possible, it would ideally incorporate deliveries into the LNG ports with the highest level of activity. Currently, the countries with the highest traded quantities of LNG are Japan, Korea and China, which collectively make up almost 90 per cent of Asian LNG demand.[225]

There are a range of sources of information on Asian LNG spot prices, which vary in terms of methodology, frequency of reporting and public availability. For example, some commodity price reporting agencies provide daily assessments of LNG spot price expectations for month-ahead cargo deliveries on the basis of surveys conducted with various market participants. There are also official sources of LNG spot price information, such as the Japanese Ministry of Economy, Trade and Industry (METI), which publishes lagged monthly averages of realised prices of LNG cargoes delivered into Japan.

The ACCC is currently assessing options for information sources on Asian LNG spot prices for the purposes of an LNG netback price series. The main criteria against which the various sources will be assessed are that:

- the prices should be representative of the broader Asian LNG spot market, and
- there is a high degree of confidence among market participants in the methodology employed to derive these prices.

The ACCC would use the chosen source of information as a basis for an LNG netback price calculation to Wallumbilla at regular intervals, such as monthly or quarterly. If the frequency of the publication of the LNG netback price differed from the frequency of reporting of the Asian LNG spot price used, then spot prices would be averaged. For example, a daily reported LNG spot price would be averaged over a month for a monthly LNG netback price, and a monthly reported LNG spot price would be averaged over a quarter for a quarterly LNG netback price.

Finally, the averaged LNG spot price would be converted to AU$/GJ. There is a range of ways that this can be done, and the ACCC is considering the most appropriate methodology.

The ACCC also notes that the ACCC is unlikely to be in position to update an LNG netback price series more frequently than monthly. Price reporting agencies are unlikely to agree to the public reporting of LNG netback prices based on their price series more frequently because the prices assessed by them are reported on a daily basis under paid subscriptions to customers. Further, other sources such as the METI are published on a monthly basis.

[225] https://www.eia.gov/analysis/studies/lng/asia/pdf/lngasia.pdf, p. 28.

Shipping costs

Asian LNG spot prices are typically reported as ‘delivered ex-ship’ (DES), which is the price of LNG delivered by ship to the destination port. For the purposes of an LNG netback price at Wallumbilla, the DES price would be netted back to the LNG exporters’ facilities at Gladstone by subtracting shipping costs and shipping losses. Shipping costs would reflect the cost of shipping LNG from Gladstone to the destination port, including ship charter costs, fuel, and port fees. Shipping losses reflect the cost (as a function of the DES price) of the quantity of gas lost during transit as a result of LNG boil-off.

Depending on the source of Asian LNG spot price information, the ACCC may use the shipping cost estimates of a price reporting agency, some of which report shipping costs on the basis of deliveries into each of the key ports in the north-east Asian market (that is, Japan, Korea and China). The ACCC understands that the destination port used for deliveries into the north-east Asian market has a negligible effect on the estimate of total shipping costs because of the similar distances to each major port.

Alternatively, the ACCC could use information obtained from the east coast LNG exporters under this inquiry to estimate the average costs that they incur in shipping LNG cargoes between Gladstone and the destination ports.

Liquefaction costs

Once shipping costs and losses are deducted from the DES price, this gives a free on-board (FOB) price, which represents the price of LNG at the point it is loaded onto a ship at Gladstone. The FOB price would then be netted back to Wallumbilla by subtracting the short-run cost of liquefaction, which consists of the cost of fuel gas and operating expenditure. The cost of fuel gas reflects the cost of the quantity of gas consumed during the liquefaction process to operate the liquefaction facility, while operating expenditure reflects the variable costs of the liquefaction process.

The calculation of an LNG netback price at Wallumbilla would not, however, account for any fixed costs of LNG production or the recovery of the capital invested in the LNG facilities. Fixed costs that cannot be avoided are not typically taken into account in making short-term commercial decisions. That is, it would be expected that when an LNG exporter is deciding whether to sell excess gas to the domestic market or for export, it would do so on the basis of a comparison between the FOB price at Gladstone and the sum of the domestic gas price and the short-run cost of liquefaction.

It is noted that the same reasoning about fixed costs also applies to the cost of transporting gas from production fields to the LNG facilities. Some of the east coast LNG exporters own and operate the pipelines they use for transmission to their LNG facilities, while others pay tariffs for the use of pipelines operated by other parties with 100 per cent take or pay obligations. In either case, the ACCC considers the costs incurred in respect of this transportation to be fixed costs and would therefore not take them into account in the calculation of an LNG netback price series.

For the purpose of the LNG netback price series, the ACCC would periodically collect information about operating expenditure relating to the liquefaction process from each of the east coast LNG exporters. This information would likely be collected on a quarterly basis. These costs would then be averaged across the three LNG exporters and the average would then be used to net back the FOB price to Wallumbilla.

6.3.2. LNG netback price based on forecast LNG spot prices

In addition to publishing an LNG netback price series based on current and past Asian LNG spot prices, the ACCC is also considering extending the LNG netback price series to the end of the following calendar year, based on market expectations of future Asian LNG spot prices. This would provide gas users who are in the process of negotiating GSAs for the subsequent year with a measure of the potential LNG netback prices for that period. However, as discussed in section 2.3.1, forecasts of future Asian LNG spot prices are inherently uncertain and expectations about the Asian spot market could change significantly over time, as has been observed over the past few months.

Should the ACCC proceed with this approach, the ACCC would continue to use the same methodology for calculating the LNG netback price, but would need to consider the source of the inputs. As with an LNG netback price series based on current Asian LNG spot prices, the ACCC would need to decide on a source of forecasts of future Asian LNG spot prices. As discussed in section 2.3.1, the ACCC has used CME Group LNG futures quotes (based on the Platts JKM) as a source for market expectations on Asian LNG spot prices in calendar 2018. The ACCC could use the most recent JKM futures quotes (as at the time of publication) as an input into a forward LNG netback price calculation.

As the ACCC is not in position to predict changes in liquefaction and shipping costs, the ACCC would likely need to use the estimates of shipping and liquefaction costs (as at the time of publication) in deriving the forward LNG netback price.

6.3.3. Consultation

The ACCC invites interested parties to contact the ACCC to discuss the LNG netback price methodology set out in this section (gas.inquiry@accc.gov.au).

The key issues on which the ACCC seeks views are as follows:

- whether an LNG netback price at Wallumbilla, published regularly on the ACCC's website, would be useful and desirable
- whether an LNG netback price should be based on LNG spot prices or prices under long-term LNG contracts, or both
- whether an LNG spot netback price based on prices in Asian LNG spot markets is appropriate
- what would be the most appropriate source of information on Asian LNG spot prices, taking into consideration the representativeness of the price measure and the methodology used by the reporting entity
- what would be the most appropriate methodology to convert Asian LNG spot prices into Australian dollars
- the ACCC's described approach to accounting for shipping and liquefaction costs.

Appendix A

There are now three forms of pipeline regulation which can be summarised as follows:

- **Full regulation:** A pipeline subject to full regulation must periodically submit a 'full access arrangement' to the AER and obtain its approval for the proposed price and non-price terms and conditions of access that will apply to the reference service(s) (a service that is sought by a significant portion of the market) over the regulatory period. When assessing the proposed access arrangement, the AER is required to have regard to the relevant provisions in the NGR and the revenue and pricing principles in the NGL. Although AER approval of an access arrangement is required, the pipeline operator and shippers on contract carriage pipelines can still enter into agreements that differ from the approved arrangement.
- **Light regulation:** This form of regulation is more akin to the negotiate-arbitrate model with greater emphasis placed on commercial negotiation and information disclosure and 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 or other conduct that may adversely affect access or competition in other markets.
- **Information disclosure and arbitration framework – Part 23 of the NGR:** Pipelines not subject to full or light regulation are subject to the new Part 23 of the NGR. This part requires the pipeline operator to publish financial and usage information according to a financial reporting guideline produced by the AER. Shippers will use this information to help them negotiate GTAs with pipeline operators. Where parties cannot reach agreement, a party can seek arbitration under Part 23.

Table A.1: Regulatory status of the major east coast transmission pipelines

	Pipeline	Owner	Regulatory Status
QLD	Roma to Brisbane Pipeline	APA	Full regulation
	South West Queensland Pipeline	APA	Part 23
	Wallumbilla to Gladstone Pipeline	APA	Part 23 and 15-year no coverage
	APLNG Pipeline	APLNG	15 -year no coverage
	GLNG Pipeline	GLNG	15 -year no coverage
	Queensland Gas Pipeline	QGP	Part 23
	Carpentaria Gas Pipeline	APA	Light regulation
NT	Northern Gas Pipeline	Jemena	n.a.
	Amadeus Gas Pipeline	APA	Full regulation
	Bonaparte Gas Pipeline	EII (APA 19.9%)	Part 23
NSW	Moomba to Sydney Pipeline	APA	Part 23: Moomba to Marsden / Light regulation: Remainder
	Eastern Gas Pipeline	Jemena	Part 23

VIC	Victorian Declared Transmission System	APA	Full regulation
Tas	Tasmanian Gas Pipeline	TGP Pty Ltd	Part 23
SA	SEAGas Pipeline	Rest / APA	Part 23
	Moomba to Adelaide Pipeline System	Epic	Part 23