Gas Inquiry 2017–2020

Interim Report

September 2017

Australian Competition and Consumer Commission
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22 September 2017

The Hon Scott Morrison MP
Treasurer
Parliament House
CANBERRA ACT 2600

Dear Treasurer

Inquiry for improving the transparency of gas supply in Australia

On 19 April 2017, pursuant to section 95H(1) of the *Competition and Consumer Act 2010*, you directed the ACCC to conduct a wide-ranging inquiry into:

- measures to improve the transparency of gas supply arrangements in Australia
- the supply by persons in the gas industry of, and demand for, natural gas extracted or produced in Australia, or imported into Australia and
- the supply of, and demand for, natural gas transportation services in Australia by persons in the gas industry.

The ACCC has also been directed to submit interim reports to you no less frequently than every six months and provide information to the market as appropriate. The first of our reports focuses on likely supply and demand conditions in the east coast gas market for 2018, where there are immediate and apparent supply concerns.

I am pleased to enclose and present the first report to you.

Yours sincerely

R Sims

Rod Sims
Chairman

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
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
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

NCC	National Competition Council
NOPTA	National Offshore Petroleum Titles Administrator
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
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline

Glossary

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.

The ACCC's previous inquiry: The ACCC's 2015 inquiry into the east coast gas market, as reported on in April 2016.

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: 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 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.

Legacy contracts: Gas supply agreements executed prior to 2010 that are still in effect and that have not been subject to a price review.

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.

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.

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.

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 amount.

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 amount.

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 amount.

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.

Units of Energy

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

Gigajoule (GJ)—a billion (109) joules

Terajoule (TJ)—a trillion (1012) joules

Petajoule (PJ)—a quadrillion (1015) joules

Million British Thermal Units (MMBT)

1. Introduction to 2018 East Coast Gas Market outlook

This is the first interim report of the Australian Competition and Consumer Commission's (ACCC) inquiry ('the Inquiry') into gas supply arrangements in Australia. The report focuses on the supply-demand outlook for 2018 in the East Coast Gas Market[1], where there are immediate and apparent supply concerns.

The supply-demand outlook in the East Coast Gas Market in 2018 has significantly deteriorated since the ACCC's previous inquiry.[2] Under current projections, there is likely to be a substantial gas supply shortfall in 2018. Commercial and industrial (C&I) users are experiencing a very difficult contracting environment in 2017, with few suppliers offering gas at very high prices for supply in 2018 and beyond.

This is consistent with the expectations of key suppliers. One supplier commented in its internal board documents that 'the east coast gas market is short and estimated to remain so over the long term'.

The ACCC has compared its estimates of gas supply in the East Coast Gas Market for 2018 with estimates of demand for this period, based on estimates of exports obtained from the liquefied natural gas (LNG) producers in Queensland and the Australian Energy Market Operator's (AEMO) projections of domestic demand. This is shown in Table 1.1, which sets out the ACCC's estimates of the projected supply shortfall for 2018 if domestic demand in the east coast falls at the lower limit or the upper limit of AEMO's domestic demand forecasts (described in the table as 'expected domestic demand' and 'upper band domestic demand' respectively).[3]

Table 1.1 – Supply and demand outlook in the East Coast Gas Market for 2018[4]

	Expected domestic demand (PJ)	Upper band domestic demand (PJ)
Supply	1901	1901
Domestic demand[5]	642	695
LNG demand	1314	1314
Projected shortfall	**55**	**108**

Notes: Total forecast supply includes 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.

The forecast of LNG demand in table 1.1 includes up to 63.4 petajoules (PJ) of sales on international LNG spot markets forecast by the LNG export projects ('LNG projects'[6]). This

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1 Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

2 ACCC, *Inquiry into the east coast gas market*, April 2016.

3 AEMO has described the lower limit of its forecast 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.

4 The forecasts in this table are based on data as at 22 September 2017.

5 The ACCC has relied on AEMO's forecasts of domestic demand in estimating this projected shortfall.

volume accounts for the entire expected gas supply shortfall in AEMO's expected domestic demand forecast.

Producer prices observed in contracts and offers for domestic supply of gas in 2018 (and beyond) are above benchmark prices,[7] which the ACCC estimates to be around $5.87/gigajoule (GJ) in Queensland and up to $7.77/GJ in the Southern States.[8] These benchmark prices are based on forecast Asian LNG spot prices for 2018, which are expected to be low due to the oversupply of LNG on the international markets.

The levels of domestic prices the ACCC has observed under recent contracts for supply of gas for 2018, as well as a substantial number of offers yet to be settled, suggest that supply of additional gas into the domestic market may not deprive the LNG projects of profits they would otherwise earn in overseas markets.[9]

With low international LNG spot prices forecast for 2018, it may be profitable for the LNG projects to buy LNG spot cargoes to meet their long-term export commitments and divert the gas produced in the east coast into the domestic market (to the extent that contractual flexibility allows for this).

The ACCC is also aware that one of the LNG projects is currently planning to export a volume of LNG above the minimum requirements for 2018 under its long-term export contracts. The volume in excess of the minimum contractual export commitments could have been used to supply additional gas into the domestic market.

While the LNG projects have taken some steps to supply more gas into the domestic market, it is unclear to the ACCC why we are not seeing more of it and why such significant volumes of LNG are forecast to be sold on the international LNG spot markets in 2018. The ACCC acknowledges that there are likely to be some additional coordination costs (discussed below at pp. 17-18) in satisfying domestic demand compared with selling LNG on international markets. This shift would also require an agreement being reached between the joint venture parties of the LNG projects, which may have different interests.

The expected supply shortfall is reflected in the conditions being experienced by C&I users in trying to secure gas supply for 2018 and beyond. Gas prices currently being offered are very high compared with historical levels and when combined with rising electricity prices pose an increased risk to the commercial viability of some C&I users. There also appears to be a substantial amount of uncontracted demand for 2018 as at mid-July 2017.

These conditions have been exacerbated by some key suppliers, including retailers, not actively marketing gas to C&I users over the past 12–18 months. One supplier commented in its internal board documents that there is 'evidence of retailers, with the exception of Origin, declining to provide proposals for continued supply of gas throughout 2017 and beyond, citing lack of portfolio supply'.

The report is structured as follows:

- chapter 1 provides an overview of the findings of this report

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6 'LNG projects' refers to the three LNG projects in Curtis Island, Queensland, which were developed to export LNG to international markets. The three entities which developed the projects are Australia Pacific LNG Pty Ltd, Gladstone LNG, and the Queensland Curtis LNG Project.

7 As discussed in section 1.4, the ACCC considers an appropriate benchmark price to be a price at which gas producers are able to recover their production costs, generate at least the same value for selling gas to domestic users as they would if the gas were sold for export and make an economic return on their investment.

8 'Southern States' is used in this report to refer to South Australian, New South Wales, the Australian Capital Territory, Victoria and Tasmania. As explained in section 1.4 and Box 4.1, increasing the level of supply and diversity of suppliers in the Southern States could result in material reductions in gas prices in the Southern States.

9 The ACCC will further examine the factors impacting on the decisions of the LNG projects in the course of the Inquiry.

- chapter 2 outlines the supply-demand outlook for 2018
- chapter 3 details the experiences of gas users
- chapter 4 discusses the gas prices currently paid and expected for 2018.

1.1. Background to the Treasurer's direction to the ACCC to hold the Inquiry

On 19 April 2017, the Treasurer directed the ACCC to hold this Inquiry to improve transparency and to monitor gas supply in Australia, pursuant to subsection 95H(1) of the *Competition and Consumer Act* 2010 ('the Act'). The ACCC is required to submit interim reports no less frequently than every six months and provide information to the market as appropriate, with a final report to be submitted by 30 April 2020 (see Appendix 1).

The ACCC used its compulsory information-gathering powers under Part VIIA of the Act to issue notices to obtain information and documents from gas producers, LNG exporters and retailers. The ACCC has also interviewed over 20 gas users, and consulted energy market bodies, including AEMO.

The current direction follows the ACCC's previous inquiry into the East Coast Gas Market and subsequent developments, including AEMO's March 2017 GSOO that indicated a tightening of supply, high gas prices and expected near-term shortages.[10] At the time of issuing the direction to the ACCC, the government expressed concern that the east coast LNG producers had not yet clearly articulated how Australian households and businesses will get adequate supply at reasonable prices.[11]

On 1 July 2017, the Australian government implemented the Australian Domestic Gas Security Mechanism (ADGSM).[12] The ADGSM allows for the control of LNG exports in the event that it is expected that there will be a domestic gas supply shortfall. The ADGSM is designed to ensure there is a sufficient supply of gas to meet the needs of Australian consumers by requiring, if necessary, the LNG projects which are drawing gas from the domestic market to limit exports or find offsetting sources of new gas.

The Minister for Resources and Northern Australia (the Minister) wrote to the ACCC on 24 July 2017, requesting advice on:

(a) the likelihood of a shortfall in 2018 in each part of the Australian domestic gas market and

(b) if applicable, an estimate of the likely volume of the shortfall in petajoules

(c) if applicable, the key factors driving the shortfall (including, but not limited to, the extent to which LNG exports are forecast to contribute to a shortfall) and

(d) if applicable, the existence of any market impediments that might prevent export controls from practically supplying additional, reasonably priced gas to the domestic market.

The Minister is expected to make a decision about whether to make a determination for 2018 by the end of October 2017.

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10 AEMO, *Gas Statement of Opportunities for eastern and south-eastern Australia*, March 2017.

11 The Hon. Malcolm Turnbull MP, Prime Minister, Media Release, *Gas Supply*, 19 April 2017.

12 Division 6 of the *Customs (Prohibited Exports) Regulations 1958,* which have been amended by the *Customs (Prohibited Exports) Amendment (Liquefied Natural Gas) Regulations 2017.*

The ACCC provides this report to the Treasurer under his direction of 19 April 2017. We note that the information contained in this report encompasses the matters the Minister referred to in his letter of 24 July 2017 and we will not be providing separate advice to the Minister.

As mentioned earlier, this report focuses on the East Coast Gas Market, where there are immediate and apparent supply concerns, being manifested in very high prices being offered to C&I users of gas, who are generally only receiving offers from one supplier.

This report does not cover Western Australia (WA) or the Northern Territory (NT), which are currently not connected to the East Coast Gas Market.

Based on AEMO's forecast in its 2016 Gas Statement of Opportunities for WA, the ACCC does not consider there is likely to be a supply shortfall in the domestic gas market in WA.[13] WA is expected to be well supplied in the short to medium term[14], with industry commentary describing the domestic market as having 'plentiful supply and prices half those in the east', with five suppliers serving C&I users from a range of sources of supply.[15]

Likewise, the ACCC does not expect a supply shortfall in the NT in 2018. NT domestic demand, at around 25 PJ per annum, is small by comparison with the rest of Australia, and is exclusively made up of gas powered generation (GPG) demand.[16] The NT will become connected to the East Coast Gas Market upon the completion of the Northern Gas Pipeline (NGP) in late 2018, potentially allowing gas from the NT to supply the East Coast Gas Market.[17]

1.2. The East Coast Gas Market outlook for 2018 has deteriorated significantly and a significant supply shortfall is now likely

Since the ACCC's previous inquiry, the East Coast Gas Market outlook for 2018 has deteriorated significantly.

In April 2016, the ACCC reported in its previous inquiry on the unprecedented changes in the East Coast Gas Market that had occurred in the preceding four years, with the development of the export facilities by the three Queensland LNG projects. The changes brought increased uncertainty and complexity in the market, particularly for C&I users that had typically operated with long-term contracts of low-priced gas, stable non-price terms and few difficulties renegotiating their contracts when they expired. These users were now required to adapt to a situation where they found it difficult to get multiple offers for supply, prices were significantly higher and more volatile, and non-price terms were less flexible than in the past.[18]

The ACCC saw three key factors as contributing to the uncertainty about future gas supply on the east coast:

- the magnitude of gas flows to the LNG projects, which are removing gas from the domestic market
- the low oil price, which is resulting in declining investment in gas exploration and lower production forecasts for both domestic producers and LNG projects

13 EnergyQuarterly, May 2017, p. 35, AEMO; Gas Statement of Opportunities for Western Australia, December 2016, p. 51.
14 AEMO, Gas Statement of Opportunities for Western Australia, December 2016, p. 1.
15 EnergyQuarterly, May 2017, p. 35, AEMO; Gas Statement of Opportunities for Western Australia, December 2016, p. 51.
16 Oakley Greenwood, *Gas Price Trends Review*, February 2016, p. 65.
17 Jemena, Northern Gas Pipeline, See: http://jemena.com.au/industry/pipelines/northern-gas-pipeline
18 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 29-36.

- moratoria and regulatory restrictions, which are affecting onshore gas exploration and development.

These factors are continuing to influence the supply-demand outlook.

On the critical question of whether there would be sufficient supply to meet the rapidly increasing demand for gas, the ACCC in its previous inquiry considered that, in 2018, there would be sufficient supply to meet domestic demand and existing LNG export commitments from 2P reserves.[19] However, we acknowledged that the supply-demand outlook was tight and subject to the timely development of reserves and also to changes in demand forecasts.

The current Inquiry has found a very different supply-demand outlook. Under AEMO's expected domestic demand forecast for 2018, there is a projected shortfall in supply to the domestic market of up to 55 PJ if forecast LNG sales on international spot markets proceed as currently planned.

The change in our expectations for the market balance between 2016 and now is largely explained by three factors:

- projected production is now lower
- a significant volume of gas is expected to be sold on international LNG spot markets and above minimum requirements under export contracts
- projected domestic demand is higher, largely due to higher demand from GPG now being forecast for 2018.

1.2.1. Projected production is now lower and new developments will not be operating in time for 2018

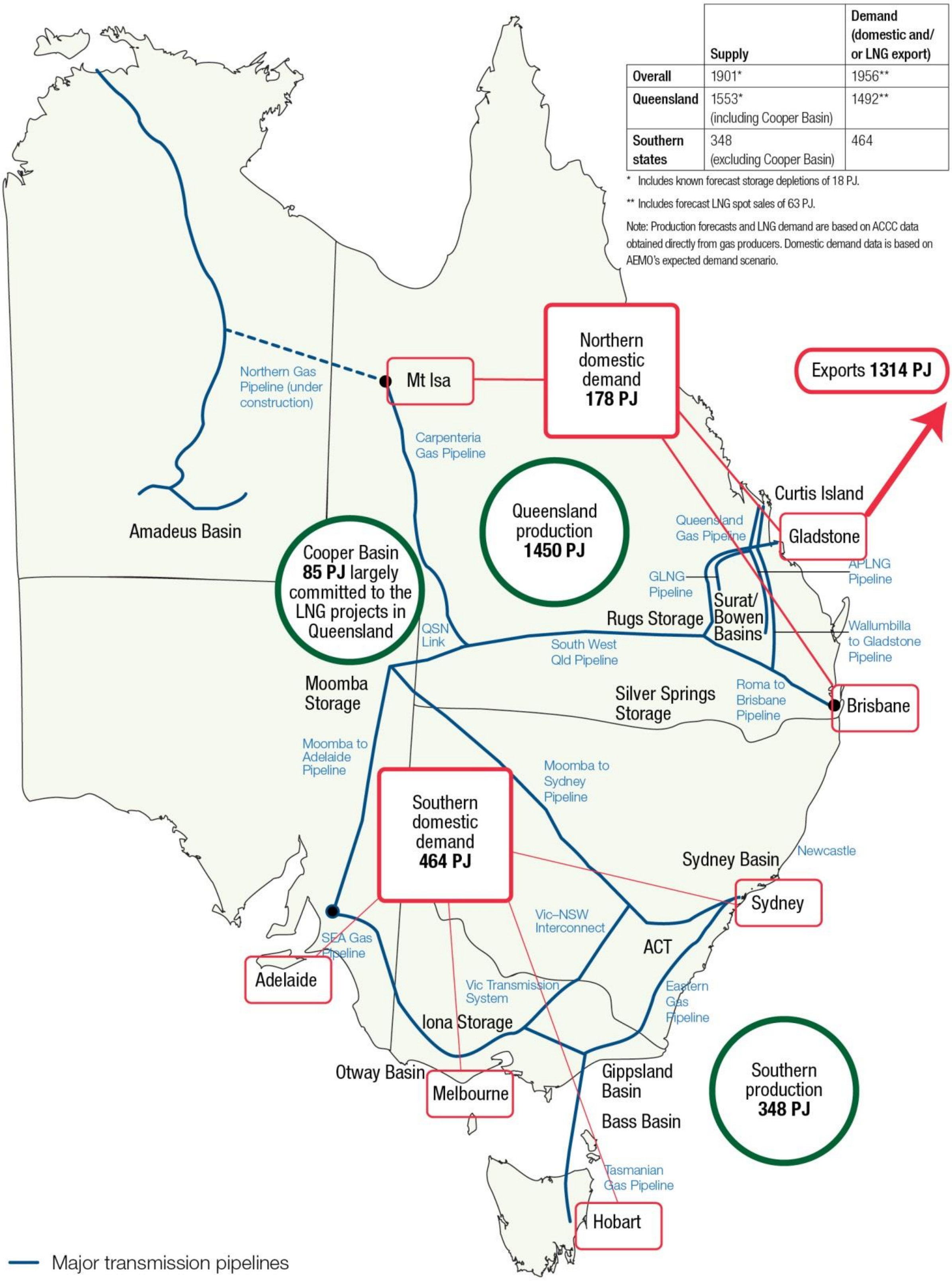
Forecast production in the Southern States (excluding the Cooper Basin) is not expected to meet domestic demand in the Southern States in 2018. Production from traditional sources of supply is forecast to continue to decline and no new supplies are expected for 2018. Production in 2018 from the Gippsland Basin Joint Venture (GBJV), which is by far the biggest producer in the Southern States, is expected to fall from a record level of 330 PJ this year to 244 PJ due to both natural decline in legacy gas fields and investment decisions made by the GBJV. While this level of production is in line with GBJV's production rates over 2011–15, this has left a significant gap in the supply needed to meet the needs of domestic users in the Southern States.

As identified by the ACCC in its previous inquiry, a significant portion of medium-term production from the Cooper Basin has been committed to the LNG projects.[20] As a result, for domestic demand in the Southern States to be met, some buyers will need to rely on supply from the LNG projects in Queensland. This is illustrated in figure 1.1. However, the LNG projects are forecasting to produce 45 PJ less in 2018 than they were forecasting in 2015.

[19] 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 amount; See ACCC, *Inquiry into the east coast gas market*, April 2016, p. 54.

[20] ACCC, *Inquiry into the east coast gas market*, April 2016, p.50.

Figure 1.1: Forecast gas production and demand in the East Coast Gas Market in 2018



Source: ACCC and AEMO data

The moratoria and other regulatory restrictions in various states referred to in our previous report continue to prevent or impede development of new gas supply[21] and gas producers do not appear to be bringing on new supply fast enough in response to the higher market prices.

While a number of projects and initiatives are on foot, these are not expected to impact the situation for 2018:

- The Longtom field in the Gippsland Basin has about 80 PJ of gas, but is currently not in production.[22] Owner Seven Group Holdings (SGH) estimates 20 PJ will be available once the project is restarted; however, this is contingent on SGH securing transportation and processing arrangements.[23]
- Cooper Energy's Sole project has been sanctioned, delivering an extra 249 PJ from offshore Victoria from 2019.[24]
- The South Australian government is subsidising the development of gas resources through the Plan for Accelerating Exploration.[25]
- The Queensland government has recently announced the results of its tender for production of new domestic supply on land adjacent to existing gas infrastructure, which the government expects will result in gas available within the next two years.[26]
- The Queensland government has also released 58 square kilometres of land for gas exploration under the condition that any gas produced must be used in Australia.[27]
- Construction of the NGP, which will link Tennant Creek in the NT to Mount Isa in Queensland, began in July 2017, with first gas flows expected in late 2018.[28] This could allow for 30–35 PJ of gas to be transported per annum.
- AGL Energy (AGL) has announced plans to develop an LNG import facility, with the preferred site being Crib Point in Victoria. If this project goes ahead, AGL intends that the terminal will be in operation by 2020–21.[29]

1.2.2. A significant volume of gas is expected to be sold on international LNG spot markets

The LNG projects appear to be aware of the domestic supply outlook, particularly in the Southern States. One of the LNG projects commented in its internal board documents that 'Queensland CSG is the only short-term supply source to meet the emerging supply gap in the south.'

The LNG projects are in a strong position to supply gas to address or mitigate the expected supply shortfall, as illustrated in chart 1.1, but a significant volume of gas is currently expected to be sold on international LNG spot markets.

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21 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 64-66.

22 SGH – FY17 Results Presentation – page 26 - http://clients2.weblink.com.au/news/pdf_2%5C01886027.pdf

23 Australian Financial Review, 'SGH Energy CEO Margaret Hall sees Longtom gas as part of solution for east coast gas', 2 March 2017

24 Cooper Energy media release, 'Finance package secures Sole FID and funds gas capex', See: http://www.cooperenergy.com.au/Upload/3.-Finance-Package-Announcement.pdf

25 Government of South Australia, PACE gas, See: http://petroleum.statedevelopment.sa.gov.au/latest_updates/pace_gas

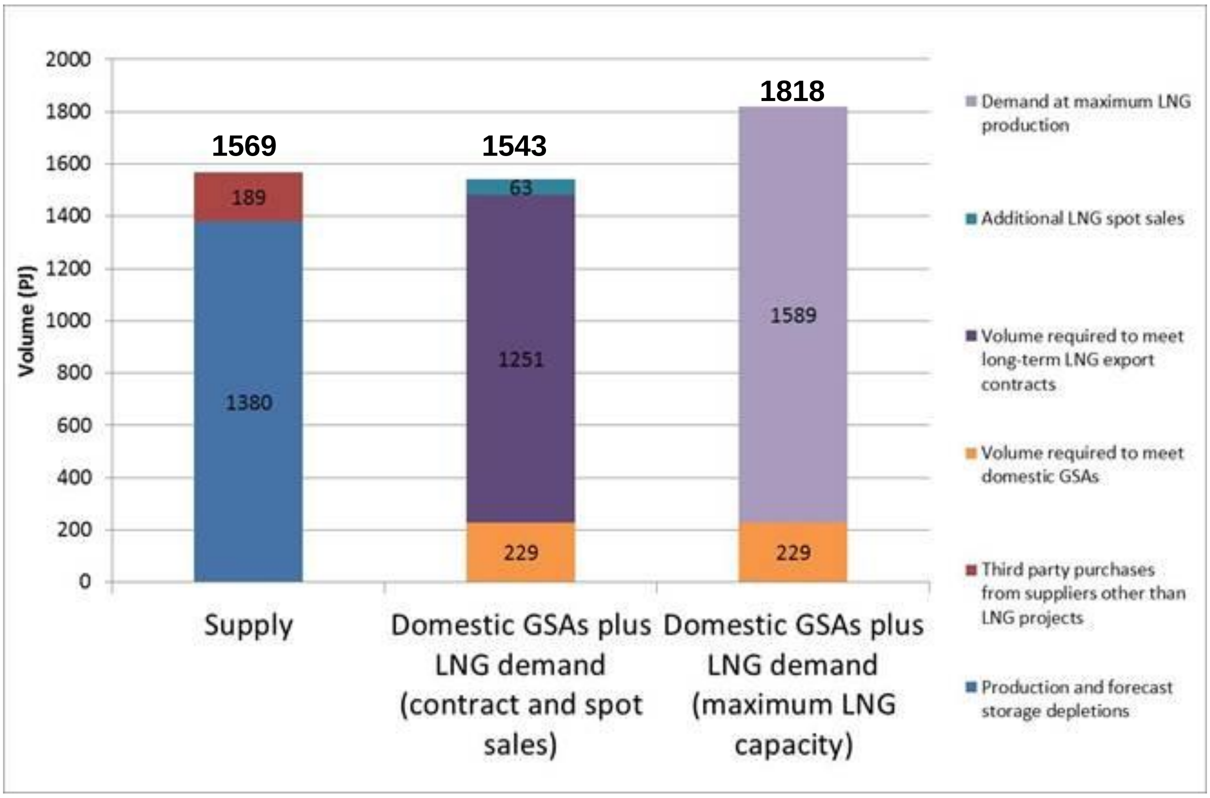
26 Queensland Government, *Palaszczuk Govt ramps up domestic gas supply*, 5 September 2017, http://statements.qld.gov.au/Statement/2017/9/5/palaszczuk-govt-ramps-up-domestic-gas-supply

27 Queensland Government, *Gas pilot aims to keep energy at home*, 25 January 2017, http://statements.qld.gov.au/Statement/2017/1/25/gas-pilot-aims-to-keep-energy-at-home

28 Jemena, Northern Gas Pipeline, http://jemena.com.au/industry/pipelines/northern-gas-pipeline

29 AGL media release, 'AGL announces Crib Point as preferred site for gas import jetty and pipeline', 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

Chart 1.1 – Supply-demand balance of the LNG projects in Queensland in 2018



Source: ACCC data.

Chart 1.1 shows that for 2018, in aggregate:

- the LNG projects are expected to contribute more gas to the domestic market than they expect to take out,[30] although this is predominantly due to legacy gas supply agreements, rather than newly executed contracts with domestic buyers
- the LNG projects' supply (production and third party purchases) is enough to meet their contractual requirements
- the LNG projects are forecast to have about 90PJ of gas in excess of this that could be used either for additional LNG export sales or to supply the domestic market, and
- the LNG projects are expecting to sell up to 63.4 PJ on international LNG spot markets.

The ACCC's examination of expected domestic prices relative to expected Asian LNG spot prices in 2018 suggests that it is likely to be more commercially attractive for the LNG projects to sell gas domestically, even when adding the additional cost of transporting the gas from Queensland to the Southern States (although this may depend on a user's location – see chapter 4).

As mentioned earlier, for exporters with flexibility in their export contracts, it may even be attractive to reduce the volume of LNG being sold under long-term export contracts or substitute locally produced gas required to meet long-term export contracts with Asian LNG spot cargoes and divert the gas to the domestic market.

[30] This is based on gas supply arrangements between the LNG projects and parties other than the LNG projects.

However, the ACCC acknowledges that there could be some coordination costs in satisfying domestic demand compared with selling additional LNG on international markets. Any decisions to divert gas into the domestic market will also require an agreement being reached between the joint venture parties of the LNG projects, which may have different interests. This may have contributed to less gas being directed to the domestic market to date than could otherwise have been expected.

The coordination issues could arise from some or all of the following factors:

- trading capabilities required to monitor short-term domestic and international markets
- the need for access to pipeline capacity to get the gas to demand centres
- differing incentives of parties involved in the LNG projects, which may not align to facilitate domestic trades
- timing coordination between production and meeting domestic demand
- lower economies of scale for trading at smaller volumes on the domestic market compared with international LNG volumes.

For gas contracted from Queensland suppliers to address southern demand, access to and pricing of transportation is a key factor in ensuring that gas flows to where it is most highly valued. As we found in the previous inquiry, however, some of the key east coast transmission pipelines are contractually congested. For example, a few holders of gas transportation rights (shippers) have contracted almost all the capacity on the vital South West Queensland Pipeline (SWQP) linking Wallumbilla to Moomba.[31] This gives these shippers a strong bargaining position in the secondary pipeline capacity market, with those seeking access having limited ability to seek alternative terms unless they are prepared to fund an expansion of the SWQP.

While a number of measures to address this have been taken, or are in the process of being considered, it will take some time for these to play out in the market.[32]

Although access to reasonably priced transportation capacity has been a challenge for LNG projects seeking to supply gas to buyers in the Southern States, market participants are starting to respond to the challenge by entering into locational swaps. While there are limits on how much gas can be swapped between locations[33], there is still some capacity for gas from the Cooper Basin that would otherwise have been supplied into Queensland to be diverted into the Southern States through a swap with the LNG projects in Queensland. In an effectively functioning gas market, it could be expected that the market participants would maximise these opportunities to ensure that gas can move to the highest valued user.

Given the importance of access to gas pipeline (transportation) capacity on reasonable terms (including prices) in facilitating the supply of gas to the Southern States, the ACCC will focus on this part of the supply chain in its next interim report in this Inquiry.

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31 For the year September 2017 to August 2018, capacity on the SWQP from Wallumbilla to Moomba was contracted 99-100 per cent. See Natural Gas Services Bulletin Board, http://www.gasbb.com.au/, accessed 7 September 2017.

32 See, for example, the work of the Gas Market Reform Group. In this context, the ACCC has also made a submission to the review by the Australian Energy Market Commission (AEMC) into the scope of economic regulation applied to covered pipelines. See: https://www.accc.gov.au/system/files/ACCC%20submission%20to%20AEMC%20Part%208-12%20pipeline%20review%20-%2016%20August%202017.PDF.

33 For example, the amount that can be swapped will depend on how much gas from the Cooper Basin would otherwise have been transported to Queensland.

1.2.3. Demand from gas-powered generators is higher than previously expected

The closure of the 1600 megawatt (MW) Hazelwood Power Station on 31 March 2017 has had a significant impact on the estimates of domestic demand by GPG in AEMO's more recent forecasts. The recommissioning of several gas powered generators that had previously not been drawing gas from the domestic market has also contributed. GPG demand under AEMO's expected domestic demand forecast is 92 PJ higher than was expected in 2015.

Levels of GPG demand can be inherently uncertain, with volumes highly dependent on weather and actions of other types of generators, particularly renewables. However, the National Electricity Market (NEM) has changed significantly in the past 12 months, which has increased the reliance on GPG.

1.3. Some gas users are facing extremely difficult market conditions and an uncertain future

1.3.1. C&I users are facing difficulties in securing competitive offers for supply

As part of the ACCC's Inquiry, we have interviewed C&I users, GPG and industry representative bodies. The industrial users interviewed represent more than a third of total industrial consumption. We have also examined offers made by suppliers over 2016–17 that had not resulted in a gas supply contract.

The current market conditions are having significant impacts on gas buyers, particularly C&I users. C&I users are experiencing difficulties in securing offers on competitive terms for supply of gas for 2018 and beyond, with most large[34] C&I users having only one supplier willing to supply them. Prices being offered are considerably higher than past levels, generally ranging from $10–16/GJ over the first half of 2017. These price offers are well in excess of competitive prices and a substantial amount of this demand appears to be currently uncontracted.

Non-price terms and conditions also reflect the current market conditions, with contracts offered being of shorter duration (generally three years or less) and with less flexible terms than historical terms of supply.

An unprecedented development in the market has been the GBJV's use of a tender process[35], where users need to bid in their prices in a 'blind' process and later discover whether or not they have been 'shortlisted'.

The situation facing C&I users appears to be caused, at least in part, by a lack of competing suppliers servicing the C&I part of the market. Internal board documents received in this Inquiry confirmed that one retailer was advising new customers to seek other sources of supply, and another retailer had internally considered substantially reducing sales to C&I customers.

Lack of access to reasonably priced transportation arrangements is also restricting options for C&I users in seeking access from alternative sources of supply.

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[34] At least 1 PJ per annum gas usage.

[35] Australian Financial Review, 'Esso-BHP Billiton gas sold at prices beyond the reach of some', 27 July 2017

These conditions are causing many C&I users to hold back on contracting for gas in the hope that conditions will improve. There have only been a small number of new contracts entered into for supply for 2018 and beyond, with a substantial number of offers not being taken up, likely on the basis of price (see chapter 4).

This situation seems increasingly likely to result in increased risk to businesses' commercial viability, with rising electricity prices also compounding pressures. Businesses that use gas as a major input into their production, either as a feedstock (such as for chemical production processes) or to generate heat in the production process (such as in the production of alumina) appear to be the hardest hit. These goods also tend to be traded on international markets where local cost increases cannot be passed on. The ACCC is concerned that current price offers could be at a level approaching the 'tipping point' where market exit by C&I users will occur – as has already been seen with Coogee Chemicals.[36] The ACCC's view is that market exit as a result of short-term prices above relevant benchmark levels would not be efficient.

1.3.2. Small businesses and vulnerable households are particularly affected

High and increasing gas prices are also having significant effects on small businesses (who report they are receiving higher priced offers for supply) and households, particularly for lower income households. As highlighted in the joint report by the Australian Council of Social Service, the Brotherhood of St Laurence and The Climate Institute, in the extreme, households may be restricting their energy usage to the detriment of their health or well-being.[37]

1.3.3. Access to reasonably priced gas for GPG is critical for electricity affordability

The effect on GPGs as users of gas is different to that faced by C&I users and by households and small business. This is particularly the case for those vertically integrated entities which own gas resources, but also gas retailers which run GPG as part of a gas portfolio. These factors allow them more flexibility in how and when they run their gas plants.

However, the rising cost of gas is one of the likely drivers of Australia's current electricity affordability issues, which is also currently being examined by the ACCC in our retail electricity inquiry.[38] GPG is increasingly the marginal source of electricity generation, and so the prices being faced by GPG are a crucial input into electricity prices. The projected gas supply shortfall will impact on those GPG which do not have long-term supply contracts, which may mean greater reliance on domestic spot markets, potentially impacting on the supply and cost of peak generation.

1.4. 2018 gas prices and price offers are above benchmark levels

Domestic gas prices have increased significantly over the past year. In Queensland, spot prices in the second quarter of 2017 were over 50 per cent higher than for the first quarter of 2016 and in the Southern States, spot prices more than doubled over the same period.

The ACCC has had regard to what are the appropriate benchmark prices in Queensland and the Southern States for 2018 for the purpose of assessing whether the prices observed in the East Coast Gas Market under new contracts are in line with the prices that would be

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36 Australian Financial Review, 'Finkel review 'too late' to save methanol plant', 12 June 2017

37 Australian Council of Social Service, Brotherhood of St Laurence, The Climate Institute, *Empowering disadvantaged households to access affordable, clean energy*, 2017, p.25

38 https://www.accc.gov.au/regulated-infrastructure/energy/electricity-supply-prices-inquiry

expected to prevail in a well-functioning market. For this purpose, the ACCC adopted the bargaining framework that was explained in the previous inquiry (see box 4.1 in chapter 4).

The ACCC considers that under this model, domestic gas prices would be expected to be at a level where producers are able:

- to generate at least the same value for selling gas to domestic users as they would if the gas were sold for export, and
- recover their costs of production and make an economic return on their investment.

As set out in the ACCC's previous inquiry, domestic prices in Queensland are now shaped by the applicable LNG netbacks.[39] Further, as discussed earlier, the three LNG projects in Queensland have sufficient gas to meet their minimum contractual export commitments for 2018 and have additional gas that could be sold on the LNG spot markets (which are likely to be the Asian LNG spot markets).

The ACCC is of the view that, in these circumstances, the appropriate benchmark price in Queensland for 2018 is the higher of:

- the LNG netback[40] based on expected Asian LNG spot prices
- the cost of production[41] of the marginal supplier in Queensland.

The ACCC estimates the Asian LNG spot netback for 2018 to be around $5.87/GJ. The information available to the ACCC indicates that the cost of production of the marginal supplier in Queensland is likely to be around the same level (see Chapter 4).

The gas prices that have been agreed in the past 18 months under long-term contracts between producers and gas buyers in Queensland for supply in 2018 are substantially above these benchmarks. The LNG projects are aware of this, with one LNG project commenting in its internal board documents that 'long term pricing in the domestic market is in excess of LNG netbacks'.

The ACCC is of the view that the benchmark price in the Southern States is higher than Queensland.

In the previous inquiry, the ACCC observed that due to the transportation cost between Southern States and Queensland, there was a range of possible pricing outcomes in gas supply negotiations in the Southern States, which fell between:

- the seller alternative – the LNG netback at Wallumbilla less the cost of transporting gas to Wallumbilla or the cost of production (whichever is higher)
- the buyer alternative – the LNG netback at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location.

The ACCC further observed that if there was sufficient supply and diversity of suppliers in the Southern States to ensure a competitive outcome, gas prices in the Southern States are likely to be closer to the seller alternative.[42]

However, as set out earlier, it is expected that production from off-shore Victoria in 2018 will not be sufficient to meet domestic demand in the Southern States and that gas from

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39 ACCC, *Inquiry into the east coast gas market*, April 2016, p.5.

40 The concept of 'netback' is explained in the glossary. It is a pricing concept based on an effective price to the producer or seller at a specific location or defined point, taking into account costs incurred between the specific location and the delivery point of the gas. See the glossary and section 4.3.1 of this report for more detail.

41 Specifically, the average incremental cost.

42 ACCC, *Inquiry into the east coast gas market*, April 2016, pp.50-53.

Queensland or the Cooper Basin is needed to balance the market. With the bulk of gas from the Cooper Basin committed to the LNG projects in Queensland, domestic buyers in the Southern States would need to contract with the LNG projects to meet their needs.

While this continues, the buyer's alternative (the delivered price of gas from Queensland to the Southern States) would be expected to shape the market price of gas in the Southern States. For example, a domestic gas buyer in Sydney would expect their delivered gas price in Sydney to be the wholesale price of gas in Queensland plus the cost of transportation from Queensland to Sydney (irrespective of whether the user purchases gas from a producer in Queensland or from a producer 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 user's location, less the cost of transporting the gas from the producer's wellhead to the user's location. For example, if a Victorian producer were to sell gas to a domestic gas buyer in Sydney, the producer would expect to receive the wholesale (ex-plant) price equal to the price in Sydney (as described in the above paragraph) less the cost of transporting the gas from the wellhead in Victoria to the user's location in Sydney (see chapter 4 for further details).

Using the Asian LNG spot netback as the Queensland benchmark price and transportation estimates from the previous inquiry, the ACCC estimates the benchmark (ex-plant) prices in the Southern States to be $6.29–7.77/GJ for 2018 (depending on the user's location).[43]

While some of the gas prices that have been agreed in the past 18 months under long-term contracts between producers and gas buyers in the Southern States are somewhat below the applicable benchmark prices, the most recent gas price agreed in Victoria exceeds the relevant benchmark price.

Further, there have been a limited number of new contracts for 2018 supply entered into in the past 18 months, both in Queensland and the Southern States. A number of C&I users are deferring agreeing to contract for 2018 supply and beyond due to the high level of prices they are being offered. Unfulfilled price offers[44] increased sharply between late 2016 and early 2017, with offers ranging between $10–16/GJ over this period – significantly above the estimated benchmark prices both in Queensland and the Southern States.

Overall, gas prices and prices offers for 2018 indicate that there is an expectation of a shortfall in the East Coast Gas Market in 2018 among the gas suppliers.

1.5. Measures to address the potential gas shortage

The significant problem highlighted in this report is one of insufficient supply to meet domestic demand. The ADGSM may go some way to addressing the shortage in the short term by limiting exports of gas from Queensland. However, the extent to which the ADGSM can address the forecast 2018 supply shortfall depends on LNG producers:

- releasing sufficient gas into the domestic market and not holding or storing gas for sales in future periods
- overcoming potential difficulties in gaining access to pipelines (due to physical capacity constraints or those holding firm rights to pipeline capacity not releasing unused capacity) to facilitate gas being transported to the Southern States, including by utilising gas swaps

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43 Producers in the Southern States would expect to receive these prices at the wellhead.

44 'Unfulfilled offers' are offers for 2018 supply of at least 1 PJ pa which have been made in writing, and subsequently not accepted.

- overcoming potential mismatches of timing and volumes of supply between that produced/released by LNG exporters and that sought by domestic gas users.

If export controls are imposed, the affected LNG projects would have to make decisions on what to do with any gas that they expect to have that can no longer be exported. To the extent that this gas cannot be coordinated and sold to meet the domestic demand for gas under longer-term contracts, this could see gas released on the domestic spot markets (the short-term trading markets or Wallumbilla Gas Supply Hub).[45]

Depending on the volume of gas that the affected LNG projects find they need to sell on these markets, this could see short-term gas prices drop significantly for short periods over the course of 2018. This could result in the LNG projects receiving a lower price than they would expect to receive on the Asian LNG spot markets. There is some risk that the LNG projects could respond to this scenario by reducing their gas production rather than selling gas to domestic users.

There are multiple factors feeding into the issue of insufficient gas supply in the East Coast Gas Market, and while it may be possible for export restrictions to address or mitigate a supply shortfall in 2018, further steps are likely to be necessary in the medium to long term to address the underlying problem of lack of gas supply and diversity of suppliers.

The ACCC considers that supply side options will provide more lasting solutions to address shortages in gas and are more likely to result in prices returning to reasonable levels. As recommended in the previous inquiry (and endorsed in the recent Finkel Review[46]), managing the risks of individual gas supply projects on a case-by-case basis rather than using blanket moratoria, and considering the effects that moratoria and other restrictions can have on gas users, would assist to increase incentives for gas exploration and may open up new sources of supply in response to high domestic prices.

Supply side solutions have the potential to have the biggest impact on prices in the Southern States. As explained earlier, increasing the level of supply and diversity of suppliers in the Southern States to eliminate the southern shortfall and increase the level of competition between suppliers in these states could result in prices in the Southern States reducing to the level of seller's alternative – i.e. an amount based on Asian LNG spot netback at Wallumbilla less the cost of transport or the cost of production (whichever is higher).

To the extent that moratoria and other regulatory restrictions in the Southern States are preventing or hindering new gas reserves from being developed that could exert a downward pressure on gas prices, these measures are contributing to the southern supply shortfall and to the resulting higher gas prices being paid by C&I users and households.

Other supply side options, such as LNG import terminals (as being considered by AGL) and additional storage facilities, may also be appropriate responses, although the case for such measures requires further investigation and analysis. It is unclear whether importing gas through an LNG regasification terminal is likely to result in reasonably priced gas being made available to domestic gas users.

1.6. Future work of the Inquiry

This is the first interim report of this Inquiry and its focus is on the supply/demand balance for the immediate future, in 2018. The Inquiry will operate for three years, with a final report due in April 2020.

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45 Other options include turning down, or shutting, gas wells or burning excess gas.

46 *Independent Review into the Future Security of the National Electricity Market*, p. 117

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

- conditions for, and pricing of, access to transportation and storage services
- the long-term supply outlook
- the reasons why the LNG projects are not entering into more international swaps that would allow them to supply more gas into the domestic market
- retailer costs and margins
- improvements to market transparency and consistency of reporting.[47]

The ACCC has sought information relating to gas transportation and storage arrangements and intends to provide some analysis on this aspect of the gas supply chain in its next report planned for late 2017. The ACCC may initially focus on key north to south transportation routes, broadening the scope of its analysis over time.

As part of our broader focus on transparency, we will periodically report on:

- LNG spot and contract netbacks (at Wallumbilla)
- producer-based and retailer-based invoiced gas price series (refer to chapter 4).

The ACCC will also make market information available as appropriate and expects to update key market information around the first quarter of 2018.

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

2. East Coast Gas Market Supply and Demand Outlook for 2018

2.1. Key points

- If the current supply and demand forecasts are realised, there will be a supply shortfall in the East Coast Gas Market in 2018 of up to 55 petajoules (PJ) in the Australian Energy Market Operator's (AEMO's) expected domestic demand forecast and up to 108 PJ in AEMO's upper band domestic demand forecast.
- The likelihood and extent of a supply shortfall will partly be affected by the level of gas-powered generation (GPG) demand (which is difficult to forecast accurately).
- The 2018 gas supply-demand balance in the East Coast Gas Market is significantly affected by the dynamics of the liquefied natural gas (LNG) projects in Queensland. Based on the current forecasts for 2018, the LNG projects are expected to, in aggregate:
  - produce over 70 per cent of the east coast's gas
  - equal two thirds of the east coast's gas demand.
- Therefore, whether a supply shortfall is in fact realised, and the extent of any such shortfall, will be materially affected by the level of production of the LNG projects and the level of LNG exports, particularly the volume of gas sold by the LNG projects on international LNG spot markets.
- With LNG projects holding about 60 per cent of proved and probable (2P)[48] gas reserves in the East Coast Gas Market, the LNG projects are in the best position to increase gas production to reduce the likelihood of a supply shortfall.
- LNG projects also currently expect to sell up to 63.4 PJ of gas on the international LNG spot markets in 2018 in addition to meeting their long-term contractual export commitments. This is notwithstanding that the Asian LNG spot prices are projected to be quite low in 2018 due to oversupply in the global LNG markets.
- Decisions made by LNG projects are likely to be particularly important for gas buyers in Southern States. Production in off-shore Victoria is forecast to be 116 PJ short of the projected domestic demand in the Southern States. This is largely a result of declining production from traditional sources of supply and no new sources of gas supply emerging in time for 2018.
- With the bulk of Cooper Basin gas contractually committed to be delivered to the LNG projects in Queensland, domestic gas buyers in the Southern States will need to rely on contracting with the LNG projects to meet their gas needs.
- While access to reasonably priced transportation capacity has been a challenge for LNG projects seeking to supply gas to buyers in the Southern States, market participants are starting to respond to the challenge by entering into locational swaps. Although there are limits on how much gas can be swapped between locations, there remains capacity for gas from the Cooper Basin that would otherwise have been supplied into Queensland to be diverted into the Southern States through a swap with the LNG projects. In an effectively functioning gas market, it could be expected that the market participants would maximise these opportunities to ensure that gas can move to the highest valued users.

[48] 2P is a measure of gas reserves that are estimated, as at a given date, to be commercially viable to produce (that is, there is at least 50 per cent probability of recovering a volume equal to, or in excess of, the estimate).

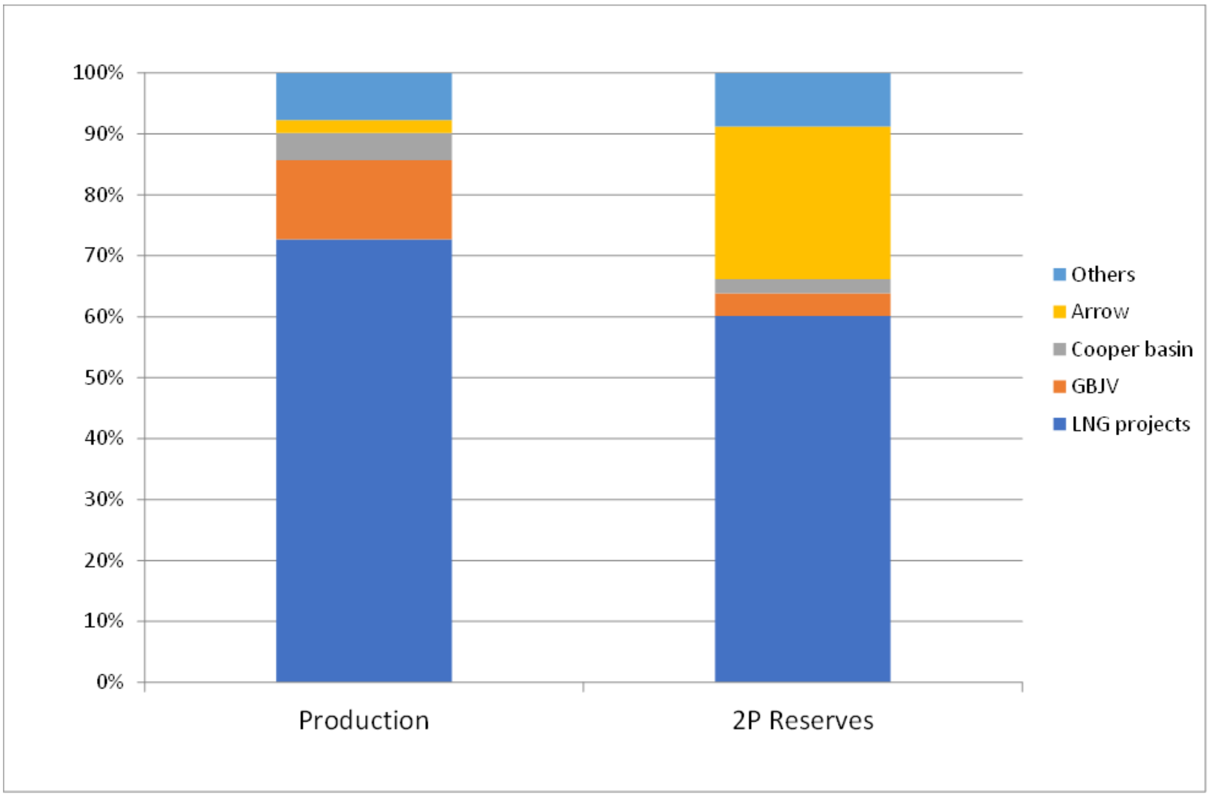
2.2. Overview of the East Coast Gas Market

The East Coast Gas Market is dominated by the three LNG export projects in Queensland. Collectively, the projects:

- hold about 60 per cent of the 2P gas reserves
- are forecast to be responsible for over 70 per cent of total gas production in 2018
- are forecast to export more than twice the amount of gas required to meet domestic demand in 2018.

Chart 2.1 below highlights the significant size of the LNG projects compared to domestic producers.

Chart 2.1 – Forecast production in 2018 and 2P gas reserves in the East Coast Gas Market



Source: Production is based on forecasts for 2018 provided by producers and noted elsewhere in this chapter, with the exception of Arrow, which is based on EnergyQuest's annual production quantity for the 12 months to June 2017. 2P reserves are based on reserve estimates from EnergyQuest's September 2017 Quarterly report.

As chart 2.1 shows, over 70 per cent of the gas production in the East Coast Gas Market in 2018 is forecast to come from the three LNG export projects in Queensland. The GBJV share is the second largest, at just under 15 per cent.

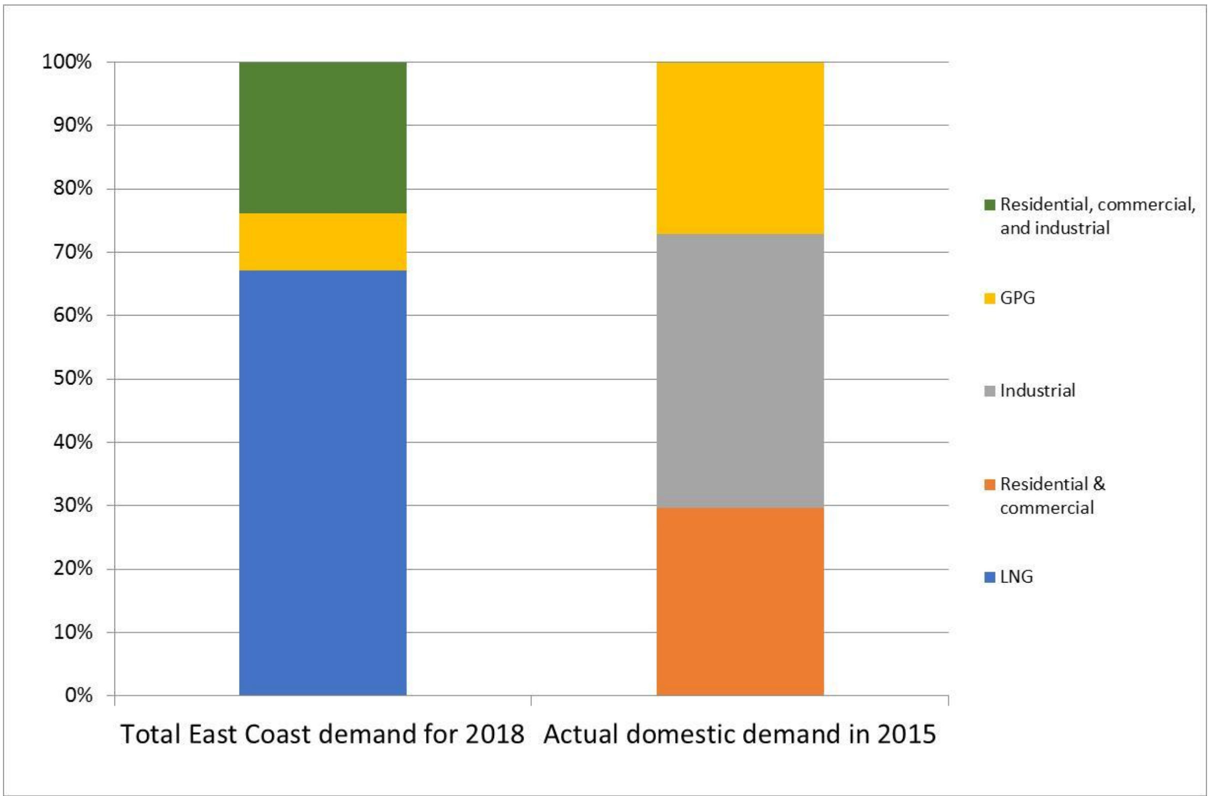
The ownership of 2P gas reserves is similar. About 60 per cent of 2P gas reserves in the East Coast Gas Market are held by the three LNG projects. The Arrow Joint Venture[49] holds the most significant uncommitted gas reserves in the East Coast Gas Market, with 25 per cent of 2P gas reserves. An announcement on future development of the Arrow

[49] A joint venture between Shell (50%) and PetroChina (50%).

reserves is expected later this year.[50] The GBJV's share of 2P gas reserves in the East Coast Gas Market is under 5 per cent.

Chart 2.2 sets out the overall demand breakdown in the East Coast Gas Market, including AEMO's forecasts of expected domestic demand and the LNG project's forecasts of export demand (including forecast LNG spot sales) for 2018. It also separately details the breakdown of the actual domestic demand in 2015 to demonstrate how it is spread across the different buyer groups. GPG demand has historically been more variable than industrial and residential demand, and this is expected to continue into 2018.

Chart 2.2 – Breakdown of forecast demand in the East Coast Gas Market for 2018 and breakdown of actual domestic demand in 2015



Source: The total east coast demand for 2018 is based on the export forecasts provided to the ACCC by the Queensland LNG projects and AEMO's expected demand forecast for GPG and residential, commercial, and industrial demand. Domestic demand for 2015 is based on demand data published by AEMO in its 2016 National Gas Forecasting Report Revised publication and available here: http://forecasting.aemo.com.au/.

The export demand from the LNG projects is by far the single largest contributor to overall expected demand in the East Coast Gas Market for 2018, at well over 60 per cent. Demand from GPG sits at around 9 per cent of the overall east coast demand.

Demand from commercial and industrial users was the biggest component of domestic demand in 2015 and this is likely to still be the case for 2018.

2.3. The level of domestic demand is dependent on GPG

The ACCC has assessed whether production in the East Coast Gas Market will be sufficient to meet demand in 2018. In conducting this assessment, the ACCC has considered:

- production forecasts obtained directly from gas producers

[50] EnergyQuest, *EnergyQuarterly*, September 2017.

- LNG demand forecasts obtained directly from the three LNG projects in Queensland, and
- AEMO's forecast domestic demand band for 2018.

AEMO has described the lower limit of its forecast demand band as what it regards to be the 'most likely to occur' demand (described in this report as 'the expected domestic demand').[51] The upper limit of AEMO's forecast demand band allows for the occurrence of uncertain but feasible conditions that could increase gas demand (described in this report as 'the upper band domestic demand').

Chapter 4 discusses appropriate benchmark prices in Queensland and the Southern States for 2018 for the purpose of assessing whether the prices recently offered or agreed in the East Coast Gas Market are in line with the prices that would be expected to prevail in a well-functioning market. The ACCC notes that if the level of domestic demand was forecast using those benchmark prices (for new contracts), it may slightly differ to AEMO's demand forecasts used in this chapter.

Table 2.1 – AEMO's domestic demand forecasts for 2018 (PJ)

User	Expected Demand	Upper Band Domestic Demand
Residential, commercial and industrial	466	492
Gas Powered Generation	176	203
Total	642	695

The level of GPG demand is more volatile relative to the demand forecasts for residential and industrial users, particularly over the short-term. This is because GPG demand is dependent on factors which are difficult to forecast accurately. For example, an increase in GPG demand could be caused by:

- lower rainfall – reducing output from hydro generation
- lower wind – reducing output from wind generation
- deferrals of renewable generation investment
- unexpected retirement of generation or unplanned outages.

The role of GPG in the national electricity market (NEM) has changed significantly over the past 12 months. The retirement of the coal fired generator Hazelwood Power Station has removed 1600 MW of capacity from the market, which has increased the reliance on other forms of generation including GPG.[52]

Key gas suppliers in the East Coast Gas Market are aware of these changes. One supplier noted in its internal board documents that these changing dynamics have 'required gas to re-enter as a flexible source of lower, intermediate and peak demand'.

AEMO's Electricity Statement of Opportunities (ESOO), published this month, sets out a number of recent developments which relate to GPG:

[51] AEMO's domestic demand forecasts are based on wholesale gas price assumptions that reflect prices expected by AEMO to be paid in the market in 2018.

[52] AEMO, *Energy Supply Outlook*, June 2017, p.11.

- Swanbank E in Queensland – intention to return to service by Q1 2018
- Pelican Point in South Australia (SA) – full station capacity is now available to the market
- Torrens Island A in SA – the mothballing of 2 x 120 MW units has been deferred to July 2019
- Smithfield Energy Facility in NSW – intention to return to service in summer 2017–18, despite originally intending to retire at the end of July 2017.[53]

This month, Hydro Tasmania announced its expectation to run the gas powered Tamar Valley Power Station to help reduce the amount of high priced electricity being imported from Victoria. Hydro Tasmania expects to run the unit as long as it is commercially favourable to do so.[54]

Information available to the ACCC indicates that AEMO's GPG demand forecast does not account for any demand from the Tamar Valley Power Station, so all else being equal, this would result in a higher level of demand from GPG than currently forecast.

2.4. The East Coast Gas Market is likely to face a significant supply shortfall in 2018

Information obtained by the ACCC indicates that the East Coast Gas Market is likely to face a significant supply shortfall in 2018 if current supply and demand forecasts are realised. This is consistent with the current expectations of key gas suppliers in the market. One supplier has described the East Coast Gas Market in its internal board documents as being 'short and estimated to remain so over the long term.'

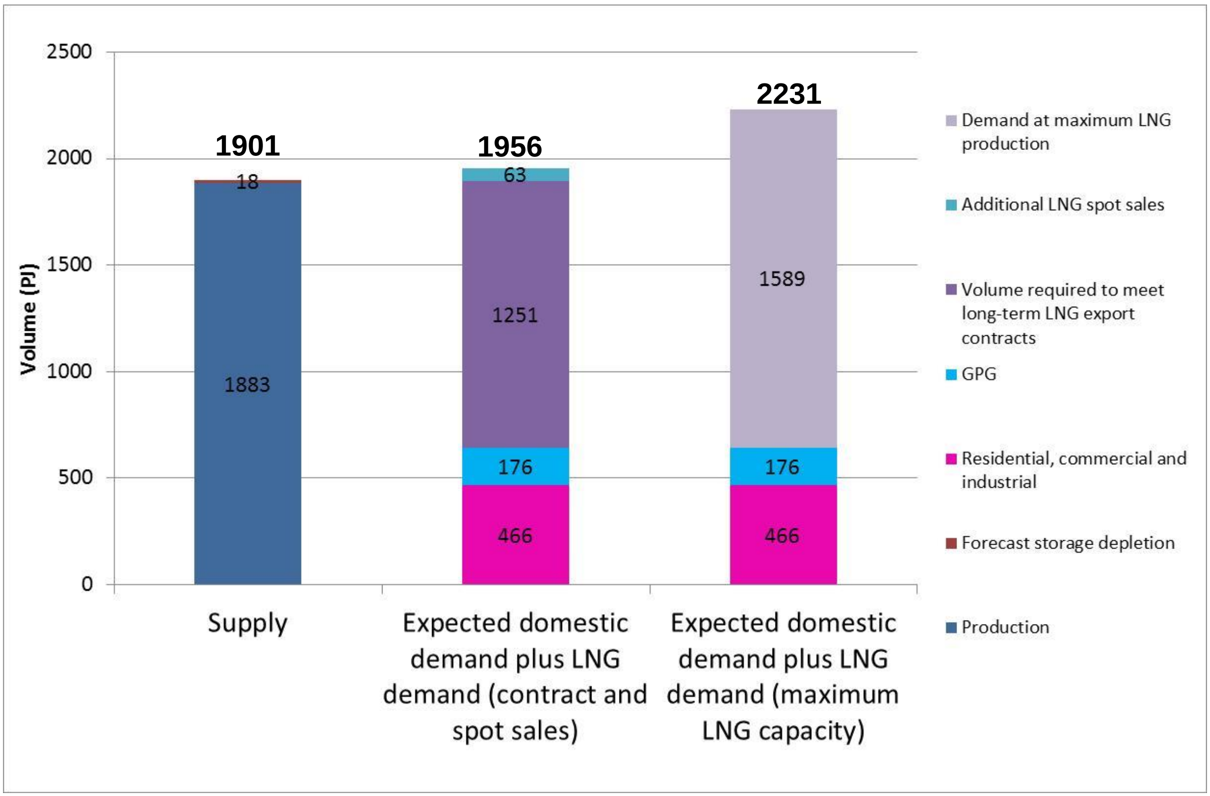
Chart 2.3 shows total forecast supply (production plus storage depletions) against two estimates of demand – total expected demand (being domestic demand plus the volumes of gas required by the LNG projects to meet their long-term export contracts and forecast LNG spot sales) and total maximum demand (being domestic demand plus the volumes of gas that would be required by the LNG projects to run their trains at full capacity). In chart 2.3, projected domestic demand is based on AEMO's expected domestic demand forecast.

Chart 2.4, shows total forecast supply against total expected demand and total maximum demand based on AEMO's upper band domestic demand forecast.

[53] AEMO, *Electricity Statement of Opportunities*, September 2017, p. 8. – https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Electricity-Statement-of-Opportunities.pdf

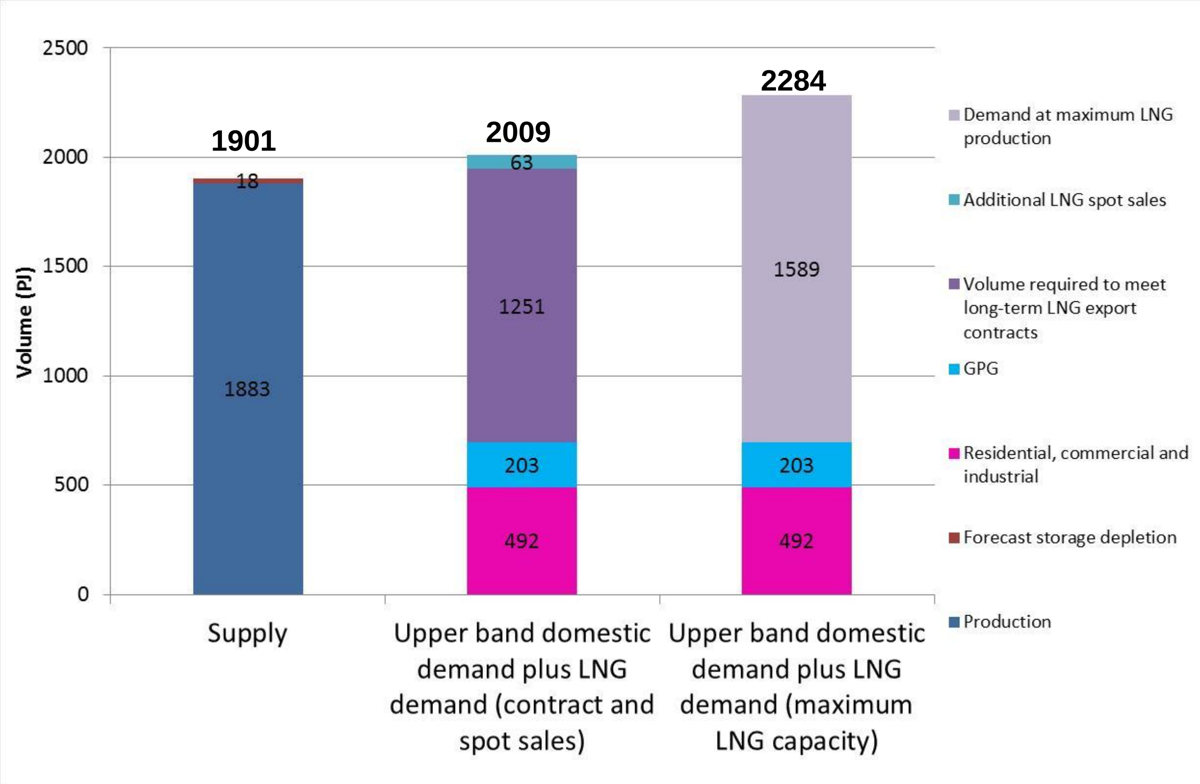
[54] Media release – Routine CCGT operation – https://www.hydro.com.au/about-us/news/2017-09/routine-ccgt-operation

Chart 2.3 – Forecast supply-demand balance in the East Coast Gas Market for 2018 (based on AEMO's expected domestic demand)



Source: ACCC and AEMO data.

Chart 2.4 – Forecast supply-demand balance in the East Coast Gas Market for 2018 (based on AEMO's upper band domestic demand)



Source: ACCC and AEMO data.

As can be seen, total forecast supply for 2018 is 1901 PJ. Total demand in AEMO's expected domestic demand forecast is 1956 PJ. Total demand in AEMO's upper band domestic demand forecast is 2009 PJ. In both cases, supply is unlikely to be sufficient to meet demand in 2018 with a potential supply shortfall 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.

Even if the LNG projects do not make any additional sales on the international LNG spot markets, the supply and demand outlook would remain finely balanced, and there would continue to be the risk of a potential shortfall. Under AEMO's expected domestic demand scenario, forecast supply would exceed the total expected demand in the East Coast Gas Market by about 8 PJ, but this could turn into a supply shortfall of up to 45 PJ under AEMO's upper band domestic demand forecast.

While the above figures are based on near-term forecasts, there are still a number of factors that may affect actual production and demand in 2018. Gas production is inherently uncertain because, although the geological presence of gas reserves and resources can be measured (to an extent), how much will be extracted remains dependent on the economic viability of carrying out the required processes. That said, the majority of forecast production for 2018 (1770 PJ) relates to developed gas production or gas production expected to be recovered through existing wells. This includes production from currently producing or sanctioned projects. Production of this type is highly certain as the capital investment to undertake the production has already been made or committed, and producers are likely to have a strong understanding of the wells' productivity.

Less certain is gas production from undeveloped areas, which accounts for 113 PJ of the total forecast production for 2018. In contrast to developed gas production, production from these 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 charts above do not include all forecast storage depletion, or take into account any forecast storage injection. The former would contribute to the overall supply pool whereas the latter would reduce the amount of gas supply available in the market. Based on information provided to the ACCC, at least 18 PJ of gas is expected to be withdrawn from the Roma Underground Gas Storage and Moomba storage facilities over 2018 and this has been included in the forecast supply for 2018. However, potential depletion of the other two large storage facilities in the east coast, Iona Storage and Silver Springs Storage, may be able to provide additional gas of around 15 PJ or more to the market depending on their operation.[55] Decisions to inject gas into these storage facilities rather than deplete currently stored gas would reduce overall supply in the market.

As noted earlier, GPG demand is dependent on a wide range of factors – many of which are difficult to forecast accurately. Recent developments in the NEM – in particular the closure of coal fired power station Hazelwood – have increased reliance on GPG. This appears likely to continue into 2018, with the level of GPG demand affecting the overall supply-demand balance in the East Coast Gas Market.

The most critical factor in relation to demand forecasts for 2018 is the level of LNG export demand. LNG projects currently forecast to have about 90 PJ of gas in excess of the volumes they require to meet their existing domestic and export contractual commitments. This gas could either be used for export or to supply domestic users. LNG projects currently expect to sell up to 63.4 PJ of this gas on international LNG spot markets. As indicated above, if these LNG spot sales are realised, the East Coast Gas Market could face a shortfall of up to 55 PJ in AEMO's expected domestic demand forecast.

As discussed in chapter 4, low LNG spot prices are currently expected in 2018 due to oversupply of LNG on the international markets. Given such low LNG spot prices and the current domestic gas prices, it is likely to be more commercially attractive for the LNG projects to sell gas to the domestic users than to overseas buyers of LNG spot cargoes.

Further, low LNG spot prices may also present the LNG projects with an opportunity to meet some of their contractual export commitments using cargoes purchased on the LNG spot markets, while selling their east coast gas to the domestic buyers (at least to the extent that contractual flexibility allows for it).

The ACCC is also aware that one of the LNG projects is currently planning to export a volume of LNG above the minimum requirements for 2018 under its long-term export contracts. The volume in excess of the minimum contractual export commitments could have been used to supply additional gas into the domestic market.

While the LNG projects have taken some steps to supply more gas into the domestic market, it is unclear to the ACCC why we are not seeing more of it and why such significant volumes of LNG are forecast to be sold on international LNG spot markets in 2018. The ACCC acknowledges that there are likely to be some additional coordination costs in satisfying domestic demand compared with selling LNG on international markets. This shift would also require an agreement being reached between the joint venture parties of the LNG projects,

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55 The estimate of 15 PJ is based on 7.5 PJ from Iona and 7.5 PJ from Silver Springs. The Iona figure is based on the current refill rate using historic patterns suggesting it may be 20 PJ full by the end of the year and noting that in the past it has been drawn down across a year to 13 PJ i.e., 31 December 2016. Whereas Iona gas storage information is visible on the bulletin board www.gasbb.com.au; AGL's Silver Springs storage isn't publicly reported but is known to be larger volume storage.

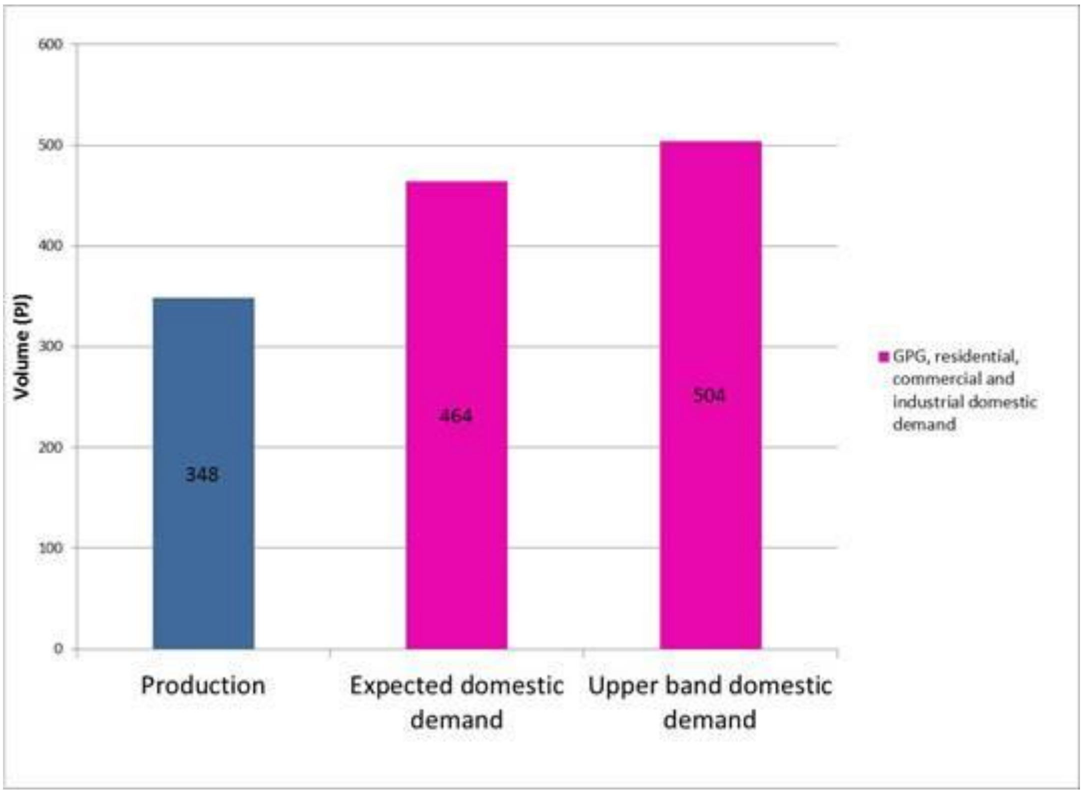
which may have different interests. This may have contributed to less gas being directed to the domestic market to date than could otherwise have been expected.

On the whole, diverting some of the east coast gas currently intended for export into the domestic market by the LNG projects is both likely to be commercially attractive for the LNG projects and may have a significant impact on the likelihood and extent of any gas supply shortfall in the East Coast Gas Market.

2.5. A significant supply shortfall is expected in the Southern States in 2018

Chart 2.5 compares forecast production and demand in 2018 for the Southern States based on AEMO's expected domestic demand and upper band domestic demand forecasts. The production forecast in the chart includes production in off-shore Victoria and Camden (NSW), but excludes production from the Cooper Basin.

Chart 2.5 – Forecast domestic supply-demand balance in the Southern States for 2018 (excluding Cooper Basin)



Source: ACCC and AEMO data.

As shown in chart 2.5, production in the Southern States is significantly less than expected demand under both AEMO's domestic demand scenarios. Forecast production in the Southern States is expected to be 348 PJ, while forecast demand is expected to be at least 464 PJ – a supply shortfall of 116 PJ in 2018.

The Cooper Basin has been excluded from the supply forecast for the Southern States because the bulk of production from the basin, which historically served the domestic market in the Southern States, has been committed to the LNG projects in Queensland.[56] However, even if all 85 PJ of the Cooper Basin forecast gas production was re-directed to domestic users in the Southern States, there would still be a projected supply shortfall of 31 PJ for 2018 in the Southern States.[57]

The expected supply shortfall in 2018 is a result of a number of factors. In the previous inquiry the ACCC flagged that there could be a significant reduction in production from traditional sources of domestic supply in the Southern States placing pressure on the domestic market.[58] This reduction in production appears to be occurring and will start having a significant impact in 2018.

Over the past two years, the GBJV, which is by far the biggest producer in the Southern States, increased its production to meet the southern demand that was no longer served by the Cooper Basin. GBJV's production is expected to reach a record level of 330 PJ in 2017. However, a significant drop in production by the GBJV is expected for 2018, with the GBJV forecasting to produce 244 PJ. Information available to the ACCC suggests that this reduction is due to a combination of the natural decline in the GBJV's legacy gas fields and investment decisions made by the GBJV. While this level of production is in line with GBJV's production rates over 2011–15, it has left a significant gap in the supply needed to meet domestic gas use in the Southern States.

Consistent with the ACCC's findings in the previous inquiry,[59] production in the Otway Basin is expected to decline from 83 PJ in 2015 to 59 PJ in 2018. This is largely due to declining production from the BHP Billiton (BHP)-operated Minerva gas field, which is expected to cease production by mid-next year. While additional production from the Origin-owned Halladale/Speculant project came online in August 2016,[60] it has only partially offset the overall decline in forecast production in the Otway Basin.

Cooper Energy recently announced that it has sanctioned the Sole gas project in the Gippsland Basin, which is expected to produce about 24 PJ per annum (discussed further below). While this will provide much needed gas for the Southern States, production won't commence in time for 2018.

Beyond this project, there are very limited prospects of new gas supply emerging from production basins in the Southern States in the immediate future. This has been exacerbated by moratoria and various regulatory restrictions in Victoria, NSW and Tasmania.

On the demand side, as discussed earlier, the evolving role of GPG in the NEM has resulted in GPG demand that is stronger than previously expected.

Given the significant expected supply shortfall in the Southern States in 2018, domestic users in these states will be increasingly relying on gas supply from the LNG projects in Queensland to meet their needs. This is consistent with current expectations of the key suppliers in the East Coast Gas Market. One supplier commented in its internal board documents that 'Queensland coal seam gas is the only short term supply source to meet the emerging supply gap in the south'.

56 The ACCC notes that in an ASX media release on 14 August 2017, Santos announced it had signed a gas supply agreement with ENGIE to supply 15 PJ of gas (comprising a mixture of GLNG and Santos portfolio gas) over two years from January 2018 for its Pelican Point Power Station in South Australia.

57 If forecast storage depletions from Moomba were also included, this would reduce the southern shortfall further, but not eliminate it.

58 ACCC, *Inquiry into the east coast gas market*, April 2016, pp.59-61.

59 ACCC, *Inquiry into the east coast gas market*, April 2016, p.60.

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

The ability of gas to be transported from Queensland to the Southern States will depend on whether the LNG projects are able to gain access to pipeline capacity at reasonable prices.

In the previous inquiry, the ACCC found that some transmission pipelines are contractually congested and also found evidence that a large number of major pipelines were using their market power to engage in monopoly pricing.[61] The ACCC will re-examine the pipeline sector in its next report, noting that a number of amendments to the pipeline regulatory framework have been made following the last inquiry, including the introduction of a new information disclosure and arbitration framework for non-scheme (previously unregulated) pipelines.

This new framework, which took effect on 1 August 2017, is expected to reduce the imbalance in bargaining power that shippers can face when negotiating with pipeline operators and pose a constraint on the exercise of market power by pipeline operators by:

- requiring pipeline operators to publish the information shippers need to make an informed decision about whether to seek access to a pipeline and to assess the reasonableness of a pipeline operator's offer; and
- allowing shippers and pipeline operators to have recourse to a commercially oriented arbitration mechanism, with clearly defined pricing principles, if a commercial agreement cannot be reached.[62]

It is important to note that this framework may take some time to have an effect on the prices charged for transportation services because arbitration will only be available when new gas transportation agreements are entered into, existing contracts are renewed or when new services are added to an existing agreement. The prices struck in existing gas transportation agreements are not therefore expected to change as a result of this new framework, unless the agreements have a most favoured nation clause.[63]

While obtaining access to reasonably priced transportation capacity is likely to be one of the challenges faced by the LNG projects in supplying the domestic buyers in the Southern States, market participants are starting to respond to the challenge by entering into locational swaps. For example, in August 2017, Santos announced a swap agreement whereby it will facilitate the transport of 18 PJ of gas over three years, taking delivery of gas at Wallumbilla and providing an equivalent volume of gas at delivery points in the Southern States.[64]

However, there is a limit to how much gas can be swapped between locations. For example, the maximum amount of gas from the Cooper Basin that could be swapped with the LNG projects at Wallumbilla is the amount of gas that would otherwise have flowed from Moomba to Queensland via the South West Queensland Pipeline (SWQP). While some of this gas has already been swapped with gas in Queensland, there is still a reasonable amount of gas that the LNG projects could swap with gas in the Cooper Basin for supply into the Southern States.

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

[62] GMRG, Gas Pipeline Information Disclosure and Arbitration Framework - Initial National Gas Rules: Explanatory Note, August 2017, p. 4.

[63] A contract clause which requires the pipeline operator to supply a shipper on the best terms it has given to any other shipper.

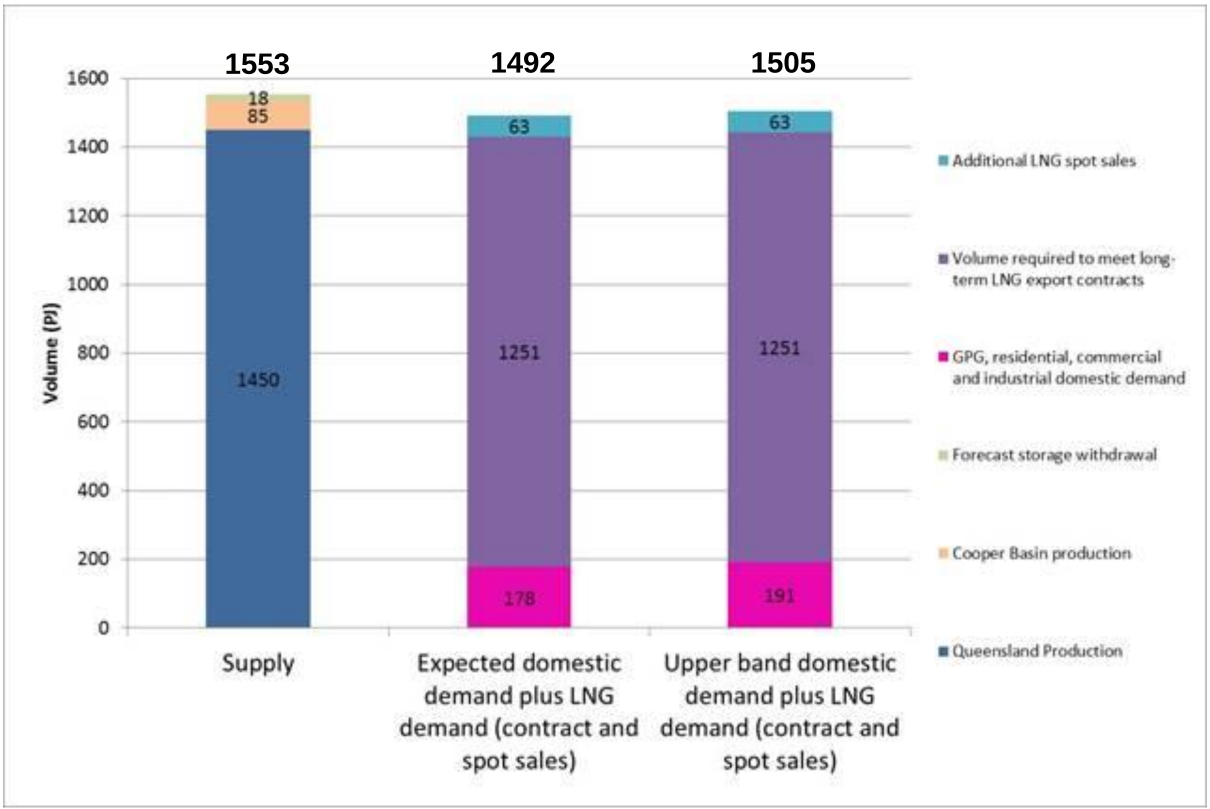
[64] Santos media release, 'Santos facilitates delivery of gas into southern domestic market', https://www.santos.com/media-centre/announcements/santos-facilitates-delivery-of-gas-into-southern-domestic-market/

2.6. Queensland is increasingly self-sufficient

2.6.1. Production in Queensland and the Cooper Basin is expected to be sufficient to meet both domestic and LNG demand in Queensland

Chart 2.6 compares forecast supply for 2018 from Queensland and the Cooper Basin (in South Australia) with forecast domestic and export demand in Queensland.

Chart 2.6 – Forecast supply-demand balance in Queensland for 2018 (incl. the Cooper Basin)



Source: ACCC and AEMO data.

Total supply is forecast at 1553 PJ, consisting of 1450 PJ from Queensland, 85 PJ from the Cooper Basin, and 18 PJ from storage. Total expected domestic demand is 1492 PJ and rises to 1505 PJ under AEMO's upper band domestic demand forecast. Each of these estimates includes the forecast export demand provided to the ACCC by the LNG projects, consisting of volumes required to meet long-term LNG contracts (1251 PJ) and expected additional international LNG spot sales (63.4 PJ).

Chart 2.6 shows that Queensland is becoming largely self-sufficient, although this is dependent on the level of LNG spot sales. In AEMO's expected domestic demand scenario, the forecast Queensland production of 1450 PJ is sufficient to meet the 1429 PJ of forecast Queensland domestic demand and long-term contractual commitments of the LNG projects. However, gas from the Cooper Basin is needed to meet the projected international LNG spot sales.

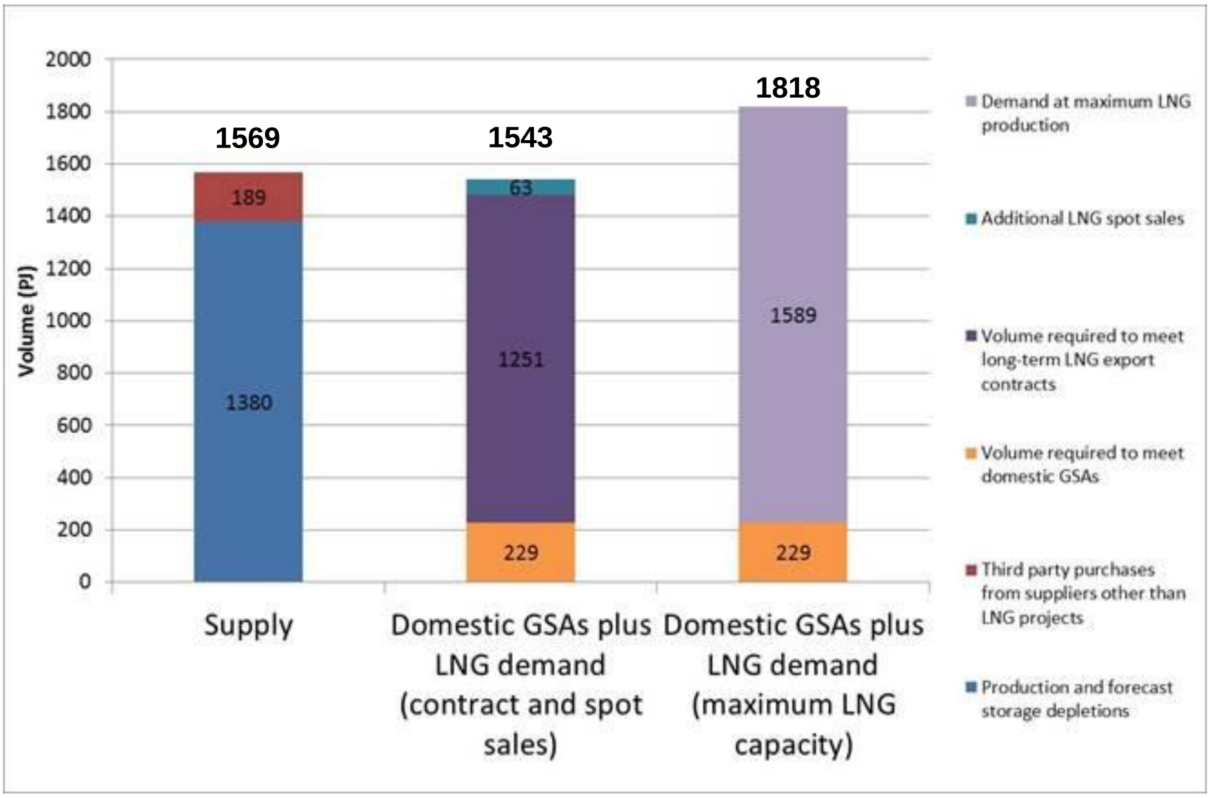
Overall, the combination of gas from Queensland and the Cooper Basin is sufficient to meet forecast demand under both demand scenarios (by 61 PJ and 48 PJ, respectively). However, the supply and demand balance improves significantly if the expected additional

LNG sales do not go ahead (which would increase available supply by up to 63.4 PJ under each demand scenario).

2.6.2. The LNG projects are forecast to have sufficient gas to meet their contractual commitments in 2018

Chart 2.7 illustrates the supply-demand balance of the three LNG projects in Queensland.

Chart 2.7 – Forecast supply-demand balance of the LNG projects in Queensland for 2018



Source: ACCC data.

Chart 2.7 shows that, in aggregate, the LNG projects are forecast to have sufficient gas in 2018 (sourced from their own production and third party purchases) to meet their domestic contractual commitments and expected exports (including forecast LNG spot sales). The total forecast supply of the LNG projects for 2018 is 1569 PJ, consisting of production and storage depletions (1380 PJ) and third party purchases (189 PJ). The total forecast demand of the LNG projects is 1543 PJ, consisting of domestic contractual commitments (229 PJ), volume required to meet long-term export commitments (1251 PJ) and forecast LNG spot sales (63.4 PJ).

However, the extent to which the three LNG projects rely on their own reserves to meet their contractual commitments varies. In particular, Gladstone LNG (GLNG) continues to rely heavily on third party gas, with Santos' Q2 Activities Report indicating third party gas accounted for over 50 per cent of the GLNG project's total gas supply.[65]

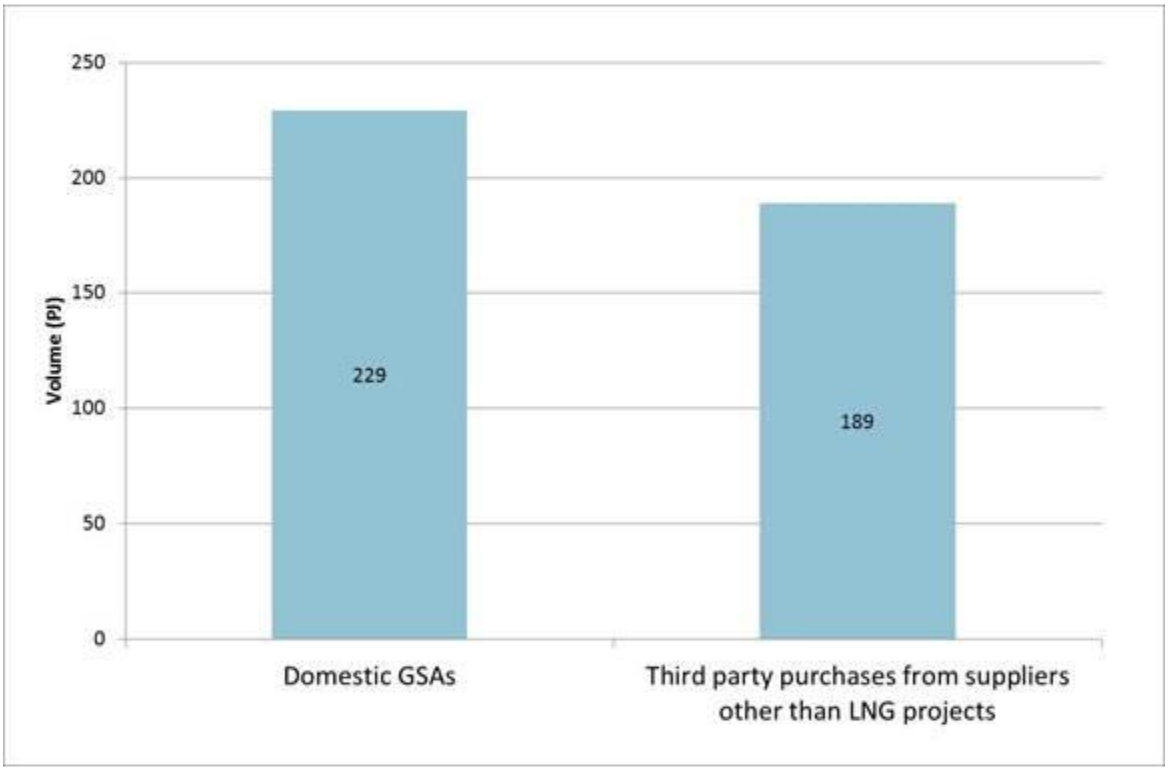
The three LNG projects are forecast to have access to about 90 PJ of gas in excess of their existing domestic and export contractual commitments (excluding LNG spot sales).

[65] Santos, *Second Quarter Activities Report*, 20 July 2017, p. 5. See: https://www.santos.com/media/3684/2017_second_quarter_activities_report.pdf

2.6.3. Participation of the LNG projects in the domestic market has been limited in recent times, but there are signs that it is increasing

Chart 2.8 compares the amount of gas the LNG projects are contracted to supply to the domestic market in 2018, with the amount of gas the LNG projects are contracted to purchase from suppliers other than each other.

Chart 2.8 – Volumes contracted to the domestic market and volumes purchased from third parties by the LNG projects in 2018 (excluding transactions between each other)



Source: ACCC data.

Chart 2.8 shows that overall the three LNG projects expect to contribute more gas to the domestic market in 2018 than they expect to take out. This is largely due to legacy gas supply agreements, rather than newly executed contracts with domestic buyers. That said, the domestic market activity of the LNG projects has increased in recent months.

QGC Pty Limited (QGC) has effectively diverted gas originally intended for LNG export to the domestic market, made possible by reducing the base annual contract quantities of the end user contracts for each of the project's trains.[66] As a result, QGC was able to enter into a number of supply agreements (most of which were for under 12 months) and some domestic spot sales.

The ACCC is also aware that earlier this year, Shell established a separate energy marketing and trading entity called Shell Energy Australia (SEA). Recent reports indicate SEA may have contracted with the Swanbank E power station in Queensland.[67]

Based on recent announcements, it appears that GLNG has been making some efforts to contribute to the domestic market. As discussed in section 1.1.1, an agreement with Engie

[66] Materials provided by QGC to the ACCC during the Inquiry.

[67] Australian Mining, 'Shell Australia signs gas supply deal in Queensland', 6 September 2017, See: https://www.australianmining.com.au/news/shell-australia-signs-gas-supply-deal-queensland/

was recently signed for supply of 15 PJ over two years to be sourced from a mixture of GLNG and Santos portfolio gas. On 7 September 2017, Santos and GLNG also announced that they will supply 30 PJ of gas to the east coast domestic market over 2018 and 2019, using gas that would otherwise have been exported as LNG.[68]

While Australia Pacific LNG (APLNG) is a net contributor to the domestic market it does not, at this stage, appear to be marketing significant additional volumes of gas to the domestic market above those volumes it has already contracted. That said, earlier this year APLNG diverted some gas to the domestic market during planned outages of its LNG trains.[69]

From April to July this year, APLNG temporarily operated both its LNG trains at 10 per cent above nameplate capacity – a requirement of its project finance tests.[70] This meant limited gas was available for redirection into the domestic market, and additional third party gas purchases were made by APLNG to support its operational requirements. With the finance tests now complete, APLNG expects to be able to more actively participate in the domestic market. APLNG has informed the ACCC that it has been in recent discussions with a number of domestic gas users.

It appears that the increased participation by the LNG projects in the domestic market has been partly due to increased scrutiny from the Australian government. For example, one of the LNG projects commented in its internal board papers that it had taken account the Prime Minister's announcement in March 2017 when making a decision to provide additional gas to the domestic market.

2.7. New sources of supply are limited and are not coming on fast enough to mitigate the expected supply shortfall in 2018

There are a number of gas resources and other measures that could be used to provide additional supply to the domestic market. However, due to long lead times, pending investment decisions and the economic viability of developing these resources, increased supply from new sources is not expected to be available during 2018.

Longtom (Gippsland Basin)

Around 80 PJ of uncontracted gas could be delivered from the Longtom field located in Victoria's Gippsland Basin – although the field is currently not in production.[71] Longtom's owner, Seven Group Holdings (SGH), recently announced that two wells are ready for production following the rectification of an electrical fault. SGH estimates that around 20 PJ will become available when the project is restarted, subject to the availability of transportation (on the Patricia Baleen Pipeline – owned by Cooper Energy) and processing (at the onshore Orbost gas plant – owned by APA Group).[72]

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[68] Santos media release, 'GLNG gas to be supplied into the east coast domestic market', 7 September 2017, https://www.santos.com/media-centre/announcements/glng-gas-to-be-supplied-into-the-east-coast-domestic-market/

[69] Materials provided by APLNG to the ACCC during the Inquiry.

[70] APLNG media release, 'Australia Pacific LNG satisfies all project finance tests', 24 August 2017, https://www.aplng.com.au/content/dam/aplng/media-release/2017/APLNG%20project%20final%20finance%20completion%20test%20-%20media%20release%20-%2020170824%20-%20FINAL.pdf

[71] SGH, FY17 Results Presentation, p. 26, http://clients2.weblink.com.au/news/pdf_2%5C01886027.pdf

[72] Australian Financial Review, 'SGH Energy CEO Margaret Hall sees Longtom gas as part of solution for east coast', 2 March 2017

Sole (Gippsland Basin)

On 29 August 2017, Cooper Energy announced that it had reached a final investment decision (FID) for the Sole gas project. The project is estimated to have around 249 PJ of 2P gas reserves.[73]

Cooper Energy expects the project will be able to supply new gas to south-east Australia in 2019, delivering around 24 PJ per annum. Supply agreements with AGL, EnergyAustralia, Alinta Energy, and O-I Australia have already been entered into.[74]

Following the FID announcement, APA will now acquire, upgrade, and operate the Orbost Gas Plant to process gas from the project.

LNG import facility

AGL is currently conducting feasibility studies into building and operating an LNG import terminal and pipeline. Recently, AGL announced that its preferred site for the facility is Crib Point (Western Port) in Victoria. AGL has described the project as having the potential to supply 'all of Victoria's household and business customer gas needs'.

AGL announced that if all goes to plan, AGL would commence construction in 2019 and bring the terminal into operation by 2020–21.[75]

Northern Gas Pipeline – bringing supply from the Northern Territory to the East Coast Gas Market

In July 2017, construction of the NGP commenced.[76] The pipeline will connect Tennant Creek in the Northern Territory to Mount Isa in Queensland and is expected to allow for the transportation of 30–35 PJ of gas per annum. While the NGP will provide an opportunity for additional gas to be supplied into the East Coast Gas Market, it is not anticipated to occur until late 2018 at the earliest.

Queensland government awarding leases with a domestic supply obligation

In September 2017, the Queensland government announced Senex had secured the rights to a petroleum lease on land in the Surat Basin. The tender marked the first time provisions of resources legislation had been used to direct gas to the domestic market. The government is hopeful production will be fast-tracked and supplying the local market within the next two years due in part to its close proximity to existing gas infrastructure.[77] A second tendering opportunity is expected to be announced soon.

Offshore South East Australia Future Gas Supply Study

In June 2017, the Minister for Resources and Northern Australia announced the Offshore South East Australia Future Gas Supply Study. The study, covering the Gippsland, Otway, Bass and Sorell basins, aims to provide an understanding of the volumes of gas potentially available from those basins for future supply to the east coast domestic gas market. The study will also assess infrastructure capacity and opportunities for additional gas supply and

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[73] Sole gas project final investment decision, 29 August 2017 - http://www.cooperenergy.com.au/Upload/4.-Sole-FID.pdf

[74] Sole gas project final investment decision, 29 August 2017 - http://www.cooperenergy.com.au/Upload/4.-Sole-FID.pdf

[75] AGL announces Crib Point as preferred site for gas import jetty and pipeline – ASX announcement - 10 August 2017 - 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

[76] Jemena, Northern Gas Pipeline, http://jemena.com.au/industry/pipelines/northern-gas-pipeline

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

accelerated development of resources. The announcement of the study cites structural change in the East Coast Gas Market and cost pressure for businesses and households as background drivers. The Australian government is working with the Victorian and Tasmanian governments, the National Offshore Petroleum Titles Administrator (NOPTA) and Geoscience Australia. The report was due to be delivered to Minister for Resources and Northern Australia by the end of August 2017.[78]

[78] Department of Industry, Innovation and Science, Offshore South East Australia Future Gas Supply Study, https://www.industry.gov.au/resource/UpstreamPetroleum/OffshorePetroleumDevelopment/Pages/SEGasSupplyStudy.aspx

3. Experiences of gas users in the East Coast Gas Market

3.1. Key points

- A key concern for most gas users is getting access to reasonably priced gas.
- Commercial and Industrial (C&I) users told the ACCC that they are experiencing difficulties in securing offers on competitive terms for supply of gas for 2018 and beyond. Most large C&I users had only one supplier willing to supply them and prices offered in 2017 were considerably higher than 2016 levels, generally ranging from $10–16/gigajoule (GJ). These prices are well in excess of appropriate benchmark prices.
- Non-price terms and conditions also reflect these difficult market conditions, with contracts offered being of shorter duration and less flexible terms than historical terms of supply.
- An unprecedented development in wholesale gas supply has been expression of interest (EOI) or auction processes, where users need to bid in their prices and later find out whether or not they have been shortlisted.
- In the face of government intervention and ACCC monitoring, negotiating conditions for C&I users have improved slightly over 2017, but prices offered are still much higher than historically. Many users are delaying signing contracts for supply for 2018 and beyond, due to the high-priced offers and in the hope that government intervention and ACCC monitoring in the market will drive prices down.
- C&I users told the ACCC that they are facing increased risk to their commercial viability, with rising electricity prices compounding pressures. Some users are facing market exit decisions. Over one third of C&I users the ACCC spoke with were considering either reducing production or closing facilities due to increasing gas prices.
- High and increasing gas prices appear to be having significant effects on small businesses and households, particularly lower income households.
- As electricity generated from gas can be expected to recoup input costs even at higher gas prices (through higher electricity prices), gas-powered generators (GPG) often experience less risk and price exposure compared with other gas users. Some GPG also have more flexibility in when they run their plants and many have alternative fuel sources available.
- The rising cost of gas is one of the likely drivers of Australia's current electricity affordability issues, with GPG increasingly being the marginal source of electricity generation. Given the important role GPG plays in the electricity market, access to affordable gas for GPG is critical for electricity market affordability. However, the tight supply and unfavourable negotiating conditions facing C&I users are also evident for those GPG that do not have long-term supply contracts. For these GPG, this may mean greater reliance on higher priced gas from domestic short-term trading markets, such that GPG may not have firm gas supply during periods of high electricity demand and they may demand higher prices to supply peak generation, to recover higher marginal costs of sourcing shorter-term gas.
- There is continued concern about access to pipeline transportation capacity and storage on reasonable terms. This will be the focus of a future interim report during this Inquiry.

3.2. Overview

Industrial gas users made up around 46 per cent of East Coast Gas Market sales in 2016. GPG accounted for around 21 per cent, and the remaining 33 per cent was consumed by residential and commercial customers.[79]

In supplying gas to a final consumer, there are up to four major cost components of the gas supply chain – wholesale gas; transporting the gas through transmission pipelines; transporting the gas through distribution networks; and retailing. Most large industrial users are directly connected to transmission pipelines so only pay wholesale and transmission costs.[80] A household's gas bill will include all four of these cost components.

To better understand the current market conditions, the ACCC has to date held discussions with a wide range of large gas users, including 18 C&I users, six GPG and three industry peak bodies[81], covering gas use across the East Coast Gas Market. The ACCC targeted users with GSAs due to expire in 2017 to gain an understanding of their experiences in attempting to secure gas supply for 2018 and onwards. Total consumption of the industrial users interviewed is about 95 petajoules (PJ) per annum, equivalent to 36 per cent of what was the total industrial consumption across the east coast in 2016.[82]

The ACCC requested information from suppliers on written offers for supply of gas that did not result or had not resulted in an agreement to supply gas, over the period 2016 and until mid-July 2017 ('the relevant period'), for supply of a minimum of 1PJ per annum ('unfulfilled offers'). The ACCC also acquired internal company board documents relevant to the supply of gas to C&I users.

The ACCC's previous inquiry found that:

> Domestic purchasers of gas, particularly industrial users, experienced an unprecedented change in their ability to obtain gas, especially in the period from about 2012 to the end of 2014 for gas to be supplied in 2016 and beyond. When seeking gas they received few, if any, real offers. Offers received were high priced, with limited volumes over shorter periods of time, had more restrictive terms and conditions and some were on 'take it or leave it' terms.[83]

Large gas users told the ACCC in this Inquiry that little has changed to the negotiating environment for new supply since the previous inquiry, and the prices offered for 2018 supply have risen considerably higher from 2016 levels. This is supported by the information gathered from producers and suppliers on unfulfilled offers made for supply for 2018 and beyond. The situation in the East Coast Gas Market contrasts with the more competitive environment in Western Australia, where users are able to access multiple offers for supply.[84]

The ACCC heard of a scarcity of offers for supply across the East Coast Gas Market, and more acutely in the Southern States, resulting in users generally having only one or, in some cases, two, suppliers to deal with to secure their gas supply. Unfulfilled offers obtained from suppliers confirm this picture, with less than half of C&I users receiving offers from more than one supplier. Generally, the users experienced a hardened bargaining approach from

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79 Australian Energy Regulator, *State of the Energy Market*, May 2017, pp. 66-7.

80 Oakley Greenwood, *Gas Price Trends Review report,* 2015.

81 The Australian Industry Group also provided the ACCC with its submission to the Deputy Prime Minister.

82 Total industrial consumption in 2016 was 263 PJ; AEMO, Gas Annual Consumption Total, forecasting.aemo.com.au – accessed 10 August 2017.

83 ACCC, *East Coast Gas Inquiry 2015*, April 2016, p. 18.

84 AEMO, *Gas Statement of Opportunities - For Western Australia*, December 2016, p 16.

producers/suppliers of gas. This was often described by users as a 'take it or leave it' approach, or in some cases a lack of interest to supply, with some suppliers not getting back with offers in response to users' repeated requests. Users also told the ACCC of particular suppliers not being willing to supply C&I users for 2018 or not supplying to users under certain large volume thresholds (of 4 or 10 PJ per annum).

In many cases where offers where made, users told the ACCC of being given only a few days to respond to the offer. The ACCC also heard that less flexible contract terms and conditions were being offered, in addition to the increased prices.

Gas users also saw a different and unprecedented approach to the offer of gas supplies in the form of EOI processes or 'auctions'.

There appears some indication of a slight improvement in conditions for C&I users over 2017. This change was likely brought about by the Australian government's policies and focus on the gas market from March 2017, including knowledge that the ACCC would be compulsorily gathering information and reporting on it publicly and to government. Some users told the ACCC that they had witnessed some increased interest in making gas offers and some reduction in the prices offered by gas producers and retailers since the government's interventions. In these conditions, many users told the ACCC that they were delaying signing contracts in the hope that conditions would improve.

C&I users told the ACCC that, in the current environment in the East Coast Gas Market, they are facing increased risk to their commercial viability. Rising electricity prices are compounding pressures on them at a time when electricity and gas markets are becoming increasingly linked.

The extent of the impact appears to depend on a range of factors, such as whether the user has alternatives to using gas, and whether they are trade exposed. Most industrial users have already exploited all opportunities to increase efficient use of energy, so reducing consumption any further will result in reduced production. Critically, some industrial users told the ACCC that they are facing market exit decisions in the next year to five years, with gas prices offered for supply from 2018 being unsustainable for long-term operations. For the majority of gas users, the uncertainty of future supply and price is placing a considerable strain on their businesses.

The ACCC also recognises that high and increasing gas prices can have significant effects on small businesses and households, particularly for lower income households and for those living in the ACT and Victoria, where the use of gas for heating is more significant.[85]

In contrast to other gas users, tightening gas supply and higher gas prices appear to be having a less pronounced effect on GPG operators. For GPG operators looking to re-contract gas supply, some have flexibility in when they run their plants and many have alternative fuel sources available.

However, difficulties in securing supply for 2018 and hard negotiating conditions are affecting some generators. A number of recent agreements for gas supply to GPG indicate that the key issue is affordability of supply, rather than a lack of gas supply that would limit generation.

For both C&I users attempting to enter the wholesale markets and for GPG, access to pipeline capacity and storage options on reasonable terms are critical for security of supply and to enable them to access additional options for supply.

[85] AER, *State of the Energy Market*, May 2017, p.151. For a low income Victorian household, gas bills represent 5.2 per cent of income – higher than for any other jurisdiction.

Users in Tasmania told the ACCC that they are facing a difficult and uncertain situation, with the agreement between Hydro Tasmania and the Tasmanian Gas Pipeline (TGP) due to expire at the end of 2017. The TGP connects Tasmania to the mainland and Hydro Tasmania supplies a number of C&I users. TGP and Hydro Tasmania are reported to have been negotiating unsuccessfully for some time on a new gas transportation agreement, with concerns that C&I users will face significant price rises as a result.[86]

Storage and pipeline capacity will be a focus of a future report of this Inquiry.

3.3. Gas supply offers

There are many large gas users in the East Coast Gas Market that will have gas contracts concluding in the next few years.[87] The experiences of most gas users that the ACCC spoke with seeking gas supply for 2018 and beyond are similar to the experiences presented in the ACCC's previous inquiry and consistent with much of the public commentary reported in the media in 2017. As more long-term legacy contracts expire, an increasing number of gas users are being affected by the difficult circumstances in securing future gas supplies.

Large industrial gas users are experiencing these pressures most acutely as they generally rely on bespoke contracts with prices, terms and conditions to suit their production requirements. In contrast, residential and small business users are typically offered standard retail contracts for predictable gas loads. This section therefore focusses on the experience of industrial gas users in the domestic gas market. Several GPGs are also seeking firm gas supply for 2018 and beyond. Their profile and experiences differ from industrial gas users, and are discussed further at section 3.5. The ACCC also recognises the significant impact of higher gas costs on smaller users, including households and small businesses, and this is discussed at section 3.4.2.

The number of suppliers making offers to gas users remains low, and users consider that the negotiating behaviour (and attitude) of suppliers appears to be inflexible and in some cases, uninterested in fulfilling users' needs. Prices offered are generally much higher than historic levels and above benchmark prices (see Chapter 4 for a discussion on pricing, including LNG netbacks) and the terms and conditions offered are increasingly inflexible and shift risk to the gas user. The location of gas users had some effect on the offers received, and, while some users noted the reform measures in train to improve gas transportation arrangements, they considered that it was too early to have observed any improvements.

The ACCC will continue to monitor and investigate gas suppliers' negotiating behaviours and the effects on gas users over the course of the Inquiry.

3.3.1. The number of interested suppliers remains low

The ACCC heard that most industrial gas users it spoke with have been approaching a number of suppliers to obtain gas offers for 2018 onwards, and have ultimately received firm offers from only one or two suppliers. Over half of the C&I users that the ACCC spoke with had received offers from only one supplier. Users told the ACCC that other suppliers they had contacted responded that they 'had no gas' for 2018, or did not respond to repeated requests for offers.

The suppliers' unfulfilled offer material is consistent with this picture of a lack of competing suppliers for business users of gas. In particular, over the relevant period, unfulfilled offers

[86] ABC News, *Tasmania's gas market could collapse without Government help, report finds*, 22 August 2017: http://www.abc.net.au/news/2016-08-22/gas-market-could-collapse-without-government-help/7775082; ABC News, *Major Tasmanian industrials told they face 95 per cent price hike for gas after deal falls through*, 5 July 2017: http://www.abc.net.au/news/2017-07-05/gas-deal-falls-through-in-tasmania/8680068

[87] Material obtained in the ACCC's previous inquiry.

were made to 23 large C&I users. Less than half of these users received offers from more than one supplier. Around 70 per cent of offers were made by two retailers.

The reported experiences of C&I users are also supported by supplier comments in their internal documents that:

- retailers, apart from one, are declining to supply, citing lack of portfolio supply
- one producer is mainly supplying gas to retailers and ‘a handful of C&I users’
- one retailer appears to have stopped quoting business customers in the later months of 2016, stating that its portfolio was fully sold, with the expectation that this retailer has a strategy of focussing on gas retail only for 2018–19
- one retailer concludes that higher gas prices ‘are likely to result in demand reduction’ and recommends reducing sales to C&I users by over two-thirds compared to 2015 volume levels
- one retailer in late 2016 was advising new customers to seek other sources of supply, because it may not be able to source additional gas.

The situation is most severe in the Southern States. Gas from offshore Victoria, particularly the Gippsland Basin, is still the predominant source of supply for southern gas users and, as discussed in Chapter 2, there is an expectation of a supply shortfall in the Southern States in 2018.

Unfulfilled offers indicate that there are only two main retailers offering supply for large industrial users, and the ACCC heard from C&I users that other suppliers were advising that they had no gas to offer at any price. One producer commented in its internal board documents that ‘retailers are now less willing to take industrial price risk’.

A number of users informed the ACCC that accessing supply from regions further north is challenging. Access is constrained by the high cost of transportation and the need to deal with multiple parties to secure access on multiple pipelines.

One user, which contracts for gas in both the Southern States and in WA, considers that contracting for gas in WA is currently easier than in either South Australia or Victoria, because of the number of suppliers (recently increased as a result of the North West Shelf Joint Venture now marketing separately), a higher number of production options and a reduced overall demand due to a reduction in WA mining activity.

In the past, Queensland users have had a greater diversity of supply options nearby compared with southern users, with an increased number of upstream gas producers that could directly negotiate and contract with large industrial end users. Many large industrial users in Queensland have very large gas consumption profiles and sophisticated gas procurement strategies, with more users engaging directly with gas producers (rather than retailers) and having their own direct gas transportation arrangements. Many of these users are still on long-term contracts and were not seeking supply for 2018.

However, users in Queensland must now compete directly with LNG projects for any gas that is available in the domestic market. As discussed in Chapter 2, Cooper Basin gas which historically supplied the southern market is now largely committed to the LNG projects in Queensland.

The lack of competing offers for supply across the East Coast Gas Market, and lack of reliable and transparent market information appears to place gas users in a weak bargaining position. Many users have been required to enter into confidentiality agreements before suppliers will even enter into negotiations.

Users told the ACCC that, where ‘genuine’ offers for supply have been made, they are generally on a ‘take it or leave it’ basis with no scope for further negotiation. One user said that it had received a ‘downright no’ when attempting to negotiate different non-price terms. Most users said that they had been given very short deadlines for responding to offers, generally ranging from 2–5 days. This is a significant constraint for many large users who are required to obtain approval from company boards and executive management before entering contracts – a process that can take weeks. For example, one large user told of being given two days to respond to an offer with the advice that otherwise the price would increase by $1/GJ. Another user shared an example of accepting an offer which was later retracted by the supplier.

Where users have received offers, they have not always been considered worthwhile, with buyers reporting instances of ‘opportunistic offers’ for very short durations of three to 12 months that were not commercially viable, or prices offered that gas users considered to be well in excess of export parity prices.

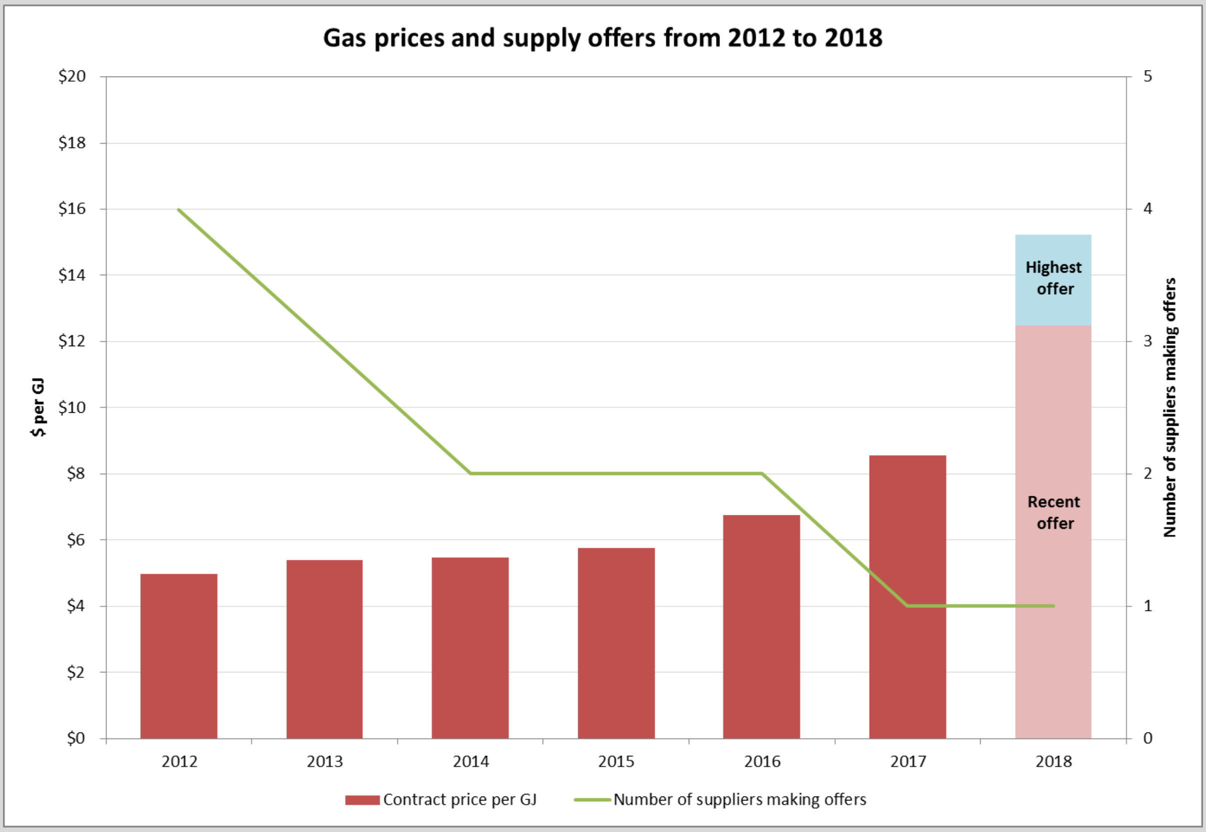
Many buyers reported that gas suppliers have no regard for the hardship of industrial users, even where longstanding mutually-beneficial commercial relationships exist. A number of market participants have observed that at least one large retailer is not interested in continuing to supply industrial gas users, viewing them as a higher risk with lower profit potential compared with residential loads. This view is supported by supplier comments referred to above. Some users reported increased minimum volume thresholds for negotiations with one producer, which cuts out small users and forces them to negotiate with an even further limited pool of suppliers.

Case study 3.3.1: Experience of how gas offers for one industrial user have changed over time

An east coast industrial user of gas with a demand of just under 1 PJ per annum is facing difficulties seeking viable gas offers for 2018. The chart below shows the buyer has been offered gas pricing at around $12–15/GJ. This is a significant increase from contracted prices in previous years of around $5–8/GJ. The number of suppliers with available offers for this buyer has fallen over the period and the buyer has received offers from only one supplier for gas in 2017 and 2018.

In response to this significant increase in gas prices, this user is exploring teaming up with other buyers to be able to access the wholesale markets.

While there may be some potential alternatives to using gas for this user, such as wood chips and solar, at present these are theoretical alternatives which the user considers to be untested in the industry.



*For 2018, the prices refer to two offers, with previous years referring to contracted prices under gas supply agreements.

In what a number of users described as a new practice, EOI processes or 'auctions' have been conducted in which prospective users need to put in a bid for their gas demand and price. This is in stark contrast to the usual practice of users seeking offers from suppliers. One of these EOI processes has been conducted by the Gippsland Basin Joint Venture (GBJV) for 2018 and 2019 supply and it is reported to have received keen interest.[88] A user is reported as describing the terms as 'not very customer friendly'.[89]

Users told the ACCC of their experiences of placing bids in these EOI and auction processes at higher than current contracted prices (one user placed a bid at 20 per cent higher than its current contracted price) but missing out on being shortlisted for supply. Users spoke of their

[88] Australian Financial Review, *Natural gas buyers line up for Esso-BHP Bass Strait tender,* 6 July 2017.

[89] Australian Financial Review, *Worried manufacturers bid for gas in nervous east coast market*, 5 July 2017. Access here: http://www.afr.com/business/energy/gas/worried-manufacturers-bid-for-gas-in-nervous-east-coast-market-20170704-gx4sny

frustration at having to bid with minimal information being provided by the supplier and noted supply terms offered were mostly short term.

There is some suggestion of a softening of supplier positions in recent months, with some users reporting the emergence of additional suppliers showing genuine interest in offering future supply. Theyconsidered that this was a result of government scrutiny and intervention in the market. However, users report that indicative prices are not attractive or comparable to what they consider to be relevant international netbacks.

3.3.2. Prices offered are generally much higher than historic levels

The ACCC has heard of prices offered to gas users that are significantly higher than prices reported in the ACCC's previous inquiry. While offers varied based on a number of factors like buyer location and volume of gas sought, the ACCC heard of prices offered in 2017 for gas supply in 2018 ranging between $10–16/GJ with anecdotal reports of offers up to $30/GJ.

Users did not see a link between LNG netbacks and the prices they were being offered, with one user telling the ACCC that it considered that there is a 'consensus price' amongst suppliers of $11/GJ, which suppliers regard as tolerable for gas users. The concept of export parity pricing and LNG netbacks was the topic of much discussion, as well as the methods used for calculating these. Users referred to LNG spot market prices as the reference, noting that they do not have visibility over contract prices. One supplier commented in its internal board documents that domestic users will need to pay above export prices for new supply over 2018–19.

The disparity between relevant LNG netbacks and prices offered is supported by the material received from suppliers on unfulfilled offers. The range of offers to C&I users for 2018 supply was $6.64–16.36/GJ, with an overall volume weighted average price offered of $10.42/GJ. These prices are often above the benchmark prices in Queensland and the Southern States (discussed in Chapter 4).

As set out in Chapter 4, relatively few contracts have been signed for 2018 supply since the start of 2016, with only seven producer and 14 retailer contracts being executed. This suggests that there is still a substantial level of unfulfilled demand for 2018. While a few of the largest users have secured gas contracts, a large number of users in the next tier down in terms of volume of gas use have not been able to secure suitable prices and terms for 2018 supply and are yet to enter into a contract, which is putting their security of supply at risk. Some users told the ACCC they were waiting to see the effect of the Australian government's interventions in the market before contracting for supply. While only a few contracts were entered into at these higher prices, these high offers are having real effects on businesses.

Consistent with the findings in the ACCC's previous inquiry, some users are continuing to see fully or partially oil-linked pricing being introduced into supply offers, which exposes them to much greater price volatility when compared with traditional consumer price index (CPI)-based price escalation arrangements.

Users also told the ACCC of what they described as the increased use of other pricing elements on top of standard supply charges, such as facility fees and overrun fees, and they argued that these fees were unfairly priced.

Since June 2017, several users have reported price offers moderating from the offers made to them by the same supplier in the first quarter of 2017. Users commented that the initial period coincided with the Australian Energy Market Operator's (AEMO's) forecast of potential supply shortages and surmised that the reductions in price offers may be the result of increased government attention. Some moderation in high prices offered in early 2017 is also apparent from the unfulfilled offer material received by the ACCC. However, these offers are still significantly higher than those seen in 2016. The prices offered are discussed further in Chapter 4.

Case study 3.3.2 below illustrates the changes in price offers received by one user.

Case study 3.3.2: How gas price offers have varied over 2017

An industrial user in NSW with gas demand of about 1 PJ per annum has been in the market during 2017 for gas supply over three years from 2018–2020. The chart below shows the range of price offers received between January and July 2017. Apart from the offers received in June, there was only one supplier offering contract terms to this user; in June, offers were received from two suppliers.

As illustrated in the chart below, the prices being offered have varied considerably over this period, with a peak of over $14/GJ offered in May for 2018 supply (as part of a three year supply term). While the latest offers shown have reduced from this level, they are still $1.42–2.52/GJ higher than offers made in January.

*Prices are in $2017 indexed for inflation, assuming a 2.5 per cent annual CPI increase.

3.3.3. Non-price terms offered are less favourable than historical terms of supply

Consistent with the ACCC's findings in its previous inquiry, the ACCC heard that suppliers and users are continuing to respond to changes in market conditions by altering their approach to contracting.[90] Some risks are being shifted from producers to gas buyers. Contracts offered are of shorter duration compared with historical terms and are less flexible. Gas users are also increasingly exposed by other changes to contract terms, like the removal of liability provisions (where the supplier's actions cause loss) and banking rights (allowing users to carry forward unused daily quantities). Because of this uncertainty and

90 ACCC, *East Coast Gas Inquiry 2015*, April 2016, p. 14.

increased risk, users told the ACCC that they are finding it difficult to make decisions about the future viability of their businesses, and about future investment decisions.

Some gas users told the ACCC that they prefer long-term contracts of at least five years, but are only receiving offers of three years or less. However, other users were only willing to seek one to two year offers in the current uncertain and high price climate. Most offers reported are for one to three years.

This is consistent with the unfulfilled offer material received from suppliers. Over the relevant period, all but one offer were for three years or less. Over 80 per cent of offers over the period were for between two and three-year terms. While only one unfulfilled offer made in 2016 was for a one-year term, in the period from January to mid-July 2017, more than a quarter of offers were for a one-year term.

Flexibility in supply volumes appears to be continuing to decrease for large gas users. Take or pay[91] levels in supply offers are higher than previous contracts for most users, with some users reporting take or pay levels up to 100 per cent where they had previously been around 70–80 per cent. As observed in the ACCC's previous inquiry, an increase in the take or pay levels from 80 per cent to 90 per cent deprives a buyer of 50 per cent of the flexibility that was previously available to them.[92]

One user told the ACCC that it was able to negotiate a reduction from 80 to 70 per cent at additional cost; however, most users reported not being able to negotiate any change at all. Limitations in take or pay flexibility has resulted in some users contracting only parts of their total load, with the remaining load requirements being met through spot markets, which increases users' price and supply risk exposure.

This was confirmed in the unfulfilled offer material received from suppliers. Over the relevant period, nearly two-thirds of offers had take or pay levels of 90 per cent or higher, and about a third of offers had take or pay levels of 80 per cent or less. Comparing take or pay levels for offers made in 2016 and offers made in 2017 (up to mid-July), the proportion of offers with a take or pay level of 90 per cent or higher increased from about 50 per cent to over 70 per cent.

Users told the ACCC that other changes to traditional contractual terms are increasing risks for large users. Banking rights have not been retained for one user's new contract offer, and restrictions are placed on some users to prevent them from acquiring additional gas from third parties or from on-selling unused gas.

The removal or reduction of contractual liability provisions is a concern for several users, who will receive limited or no compensation if the supplier is unable to deliver the full volume of gas contracted. Users say there is not enough transparency around the circumstances of supply constraints, which limits their ability to assess whether they are being treated fairly and whether other users are experiencing the same constraints. Related to this, large users are concerned that in the event of a supply shortage, they will be asked to reduce usage rather than GPGs or residential users, putting their production and potentially also their longer term commercial viability at 'unfair' risk.

Where GSAs were in place, several users noted that less gas was being delivered than contracted due to unexpected reductions in the suppliers' production. When this happens, users often have to reduce production capacity because sourcing replacement gas on the spot market is uneconomic for them at current prices (discussed in chapter 4).

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91 This is the minimum proportion of the gas supply agreement's annual contract quantity that the buyer is required to take in a particular year. The buyer is required to pay for this minimum volume of gas regardless of whether they use it. The take or pay multiplier is expressed as a percentage.

92 ACCC, *East Coast Gas Inquiry 2015*, April 2016, p. 72.

3.4. The impact of current market conditions on gas users and how they are responding

3.4.1. Commercial and industrial users are facing negative impacts on their businesses

Many C&I users have indicated that the current market conditions for gas supply have had a negative impact on their businesses. The extent of the impact on users seems to vary depending on a range of factors, such as:

- how important gas supply is to their business processes – for example, what proportion of their total costs are gas costs, and whether gas is used as an energy source or a feedstock in production, or both
- whether they have alternatives available to them, or any other type of countervailing power or relationship with suppliers
- the extent to which their products are trade exposed; that is, the extent to which they are exposed to international competition in the markets in which they supply their products.

Industrial users that produce trade-exposed products have indicated that they have had to absorb the increased gas costs rather than pass costs on to their customers, which could result in their products becoming uncompetitive in the long term.

Many of the users the ACCC spoke with are experiencing further significant increases to their input costs as a result of higher gas prices. Some of these businesses also have significant electricity usage and the higher gas prices feeding in to higher electricity costs have a compounding effect.

In response to these higher input costs, users reported that they are taking or considering a range of options. A number of users the ACCC spoke with have undertaken efficiency measures to reduce their use of gas. Where available and feasible, some users have been investigating alternative fuel sources. For example, where gas is used as an energy source for manufacturing productions, users have looked at a range of alternative fuels such as diesel or biofuels.[93]

However, users told the ACCC that switching to alternative sources is costly and will require significant upfront investments and long lead times. For example, one manufacturer is looking to offset rising energy costs by permanently reconfiguring its existing internal generation assets to maximise the use of waste process gas, which will allow it to avoid not only buying higher priced electricity from the grid but also avoid the need to use high priced natural gas for electricity generation. Some users are able to use diesel as an alternative, but view this as an expensive option and were concerned about this being a 'backward step' on environmental grounds. Some users were investigating the use of wood waste as an alternative fuel, but considered that this would require a significant investment in equipment, have negative environmental implications and there were concerns about security of supply for this too.

For some users, however, there are no viable alternatives to the use of gas for their operations and this is particularly the case where gas is a feedstock in the manufacturing process. For example, natural gas is a raw material or feedstock in the production of some

[93] For example, Adelaide Brighton Cement is reported to be taking a range of measures to reduce consumption of gas, including demand management, which switches or reduces consumption at times of low supply or high prices. It is also reported as diversifying supply sources, aiming to source up to 30 per cent of annual consumption from alternative fuels such as biogas. Source: The Australian, *Push for energy policy as soaring prices bite*, 22 August 2017, p. 17.

fertilisers, explosives, plastics and chemicals and natural gas ethane is the feedstock for ammonia production.

At worst, this may result in some businesses exiting the market where it is no longer commercially viable to continue operations, with consequent effects for production and employment. If this effect is the result of gas prices that are higher than we would expect in a well-functioning market, this is likely to result in deadweight losses for society. ACCC's views about appropriate benchmark prices in a well-functioning market are discussed in Chapter 4.

Case study 3.4.1: Market exit decisions for industrial gas users

As discussed earlier, businesses that use gas as a major input into their production are facing significant impacts from rising gas prices. Gas is used in some businesses to generate heat in industrial processes such as in the production of alumina, and as a feedstock for some chemical production processes, such as fertiliser, plastics, sodium cyanide, and ammonia, used to produce ammonia nitrate. Many of these products are traded on international markets, limiting the extent to which higher gas costs can be passed on. For many of these affected businesses, there is no viable alternative to using gas. The combination of these factors means that some of these types of businesses are facing decisions either to reduce their production or to exit the market.

Coogee Chemicals Pty Ltd, a chemical manufacturer, was reported as stating that high gas prices have forced it to dismantle its mothballed methanol plant from Melbourne and ship it to the United States to take advantage of cheaper gas.[94]

In July, Coogee reported to the ACCC that it was progressing a decision to relocate its plant to the US, where it claimed it could get gas for $2.30/GJ having previously noted to the ACCC that when it went to recontract for the plant in 2015 the prices it was offered were around $5.80/GJ with 100 per cent take or pay level.

Qenos, which operates Australia's only polyethylene plants in Melbourne and Sydney, employing 1000 workers and contractors, has featured in the media this year.[95] It uses gas as both an input to make plastic and as a fuel to power its plants. Qenos was reported as claiming that its gas bill had increased by 'many millions of dollars' over the past year and that it was struggling to secure a long-term gas supply contract to enable it to remain globally competitive. Given competition from foreign imports, Qenos said it cannot pass on rising gas costs to customers and warned that there would be an impact on jobs if some relief was not found soon.[96]

Another user who consumes a large proportion of its gas as a feedstock advised that in the long term, the higher prices could lead them to importing their key gas-based inputs rather than producing them directly.

Users told the ACCC that, where there are no viable alternatives to gas, some users are exploring alternative approaches to sourcing gas to adapt to the current market conditions. For example, a number of industrial users are now using or investigating use of the short-term trading markets (STTMs) in Sydney, Adelaide and Brisbane, the Victorian Domestic Wholesale Gas Market (DWGM) and/or the Wallumbilla Gas Supply Hub to supplement supply contracts or for sourcing their entire gas needs. However, users spoke of the costs and limitations of this approach, with a lack of confidence and liquidity in these markets compounded by the additional costs borne and resources required for participation.

94 Australian Financial Review, *Finkel review 'too late' to save methanol plant*, 12 June 2017. Access here: http://www.afr.com/news/finkel-review-too-little-too-late-to-save-methanol-plant-20170612-gwpbsf?login_token=EiMC3lvbC2FCC7X0O0BNCAVg4MJGSkwGKR-H4YzRupjbeLj9VepRhpubasDJMx3_QvwCyzNCdbcx_U-cix4fng&expiry=1501208345&single_use_token=PycHMb4xfSpuVIius3jxv9lkFxzvU7NAxAnOfSvXbqi3dxmkbXTYz_F8wLiVB4SdKFm5xhpUcF1OmYnj2aOpxg

95 Herald Sun, *Plastics maker Qenos warns Victorian jobs could be cut over gas prices*, 14 July 2017. Access here: http://www.heraldsun.com.au/business/plastics-maker-qenos-warns-victorian-jobs-could-be-cut-over-gas-prices/news-story/ed788f797b926a52c9da82faadb220e8?nk=f4912ba3c731ad7e46bee23702ce6cf7-1501207140

96 Ibid.

One user described the process of becoming a market participant in the Victorian DWGM. It described a three to four-month lead time in which it would need to register with AEMO and satisfy prudential requirements and arrange pipeline agreements. It would also need to put on additional staff for daily market monitoring and put in place daily operating strategies.

Another option being pursued by some users involves moving into unfamiliar territory by entering into upstream gas production in order to have an assured supply of gas. Incitec Pivot, an explosives chemical and fertiliser manufacturer, has revealed it was one of the parties who participated in the recent tender process for the right to extract coal seam gas from the Surat Basin as part of the Queensland government's plan to provide more gas supply to the domestic market. While it was not successful in this first tender application[97], Incitec Pivot noted that if it was successful, there would have been 10 years of gas supply for its Gibson Island fertiliser plant in Brisbane.[98]

As discussed in the ACCC's previous inquiry report, a number of industrial users had signed conditional gas agreements with Strike Energy for gas supply from the Southern Cooper Basin Gas Project in South Australia as foundation customers.[99] However, illustrating the risks involved in upstream production, as reported in June this year, Strike Energy had not delivered gas on time and was reported to be in a dispute with Orica over the timing of gas deliveries.[100] In August 2017, Orica and Strike Energy signed a revised agreement.[101]

Another option being considered by some users follows the example being set in the electricity industry by the SA Chamber of Mines and Energy who have formed a collective purchasing group of 27 SA businesses. This collective arrangement was authorised by the ACCC in May 2017.[102] Users of gas are considering similar arrangements as one option to strengthen their bargaining position to secure more competitively priced gas.

A number of suppliers are only offering gas to very large users, limiting smaller C&I users' ability to secure supply. Collective arrangements appear to be one response to try to address this situation. Three separate parties who spoke to the ACCC raised proposals for collective arrangements of this type.[103]

3.4.2. Households and small businesses are facing significant impacts

High and increasing gas prices can have significant effects on small businesses and households, particularly for lower income households and more so for those lower income households living in the ACT and Victoria, where the use of gas for heating during cold winters is more significant.[104]

The recent increase of wholesale gas costs has put upward pressure on retail gas bills and concerns about the impact on consumers have been widely expressed in the media and by

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97 Incitec Pivot Limited, ASX announcement, 5 September 2017.

98 The Australian, *Incitec Pivot says QLD's gas plans could save plant,* 9 May 2017: http://www.theaustralian.com.au/business/incitec-pivot-md-says-government-gas-plans-would-save-plant/news-story/1d54c7404296ae2132e1367f1faa4825?nk=0b25f9d14291419175ae02ddcf161af6-1501218608. The Queensland Government, *Minister for State Development and Minister for Natural Resources and Mines*, 10 February 2017: http://statements.qld.gov.au/Statement/2017/2/10/tenders-open-for-australian-gas-pilot

99 ACCC, *East Coast Gas Inquiry 2015*, April 2016, p.50.

100 The Financial Review, *Strike in dispute with Orica over late gas*, 7 June 2017: http://www.afr.com/business/energy/strike-in-dispute-with-orica-over-late-gas-20170607-gwm22j

101 Strike Energy, ASX announcement, 17 August 2017.

102 ACCC, *The South Australian Chamber of Mines and Energy Inc & Ors – Authorisation – A91567 & A91568*, 17 May 2017. Access here: http://registers.accc.gov.au/content/index.phtml/itemId/1200538/fromItemId/278039

103 The Eastern Energy Buyers Group has lodged an application for authorisation with the ACCC: http://registers.accc.gov.au/content/index.phtml/itemId/1203232/fromItemId/278039

104 AER, *State of the Energy Market*, May 2017, p.151. For a low income Victorian household, gas bills represent 5.2 per cent of income – higher than for any other jurisdiction.

consumer groups and parliamentary representatives.[105] In the ACCC's previous inquiry report, we noted that a $2/GJ increase in the wholesale gas prices could raise household gas bills by 5 per cent in NSW and 11 per cent in Victoria. However, there are other components in addition to wholesale costs that could impact on retail gas prices, such as transmission, distribution and retail costs. Wholesale gas costs generally make up 15–29 per cent of total residential gas bills depending on the state or territory.[106]

The impact of rising wholesale gas prices on retail gas bills has been partly offset by lower gas distribution pipeline charges under recent Australian Energy Regulator (AER) access arrangements for NSW (2015), SA (2016) and the ACT (2016). The AER decisions resulted in lower gas retail bills in all three jurisdictions for the year in which they took effect.[107] Residential gas bills in Victoria and the Albury region of NSW are also set to drop slightly from 2018 under recent AER draft access arrangements.[108] The NSW and ACT networks successfully appealed their AER decisions, which will result in higher retail prices relative to the AER's original determinations. The avenues for appeal of AER determinations may be more limited in the future following the expected removal of limited merits review.[109]

Increases in retail energy bills can have significant impact on households, particularly on low-income and disadvantaged households. Some impacts highlighted by the joint report by the Australian Council of Social Service, the Brotherhood of St Laurence and The Climate Institute, could include[110]:

- households who are unable to pay their energy bills on time, forgoing offered discounts for on-time payment, and potentially getting disconnected
- households who restrict their energy usage to the detriment of their health or well-being, for example living in a very cold home in winter. This often results in health or other issues
- households who trade off other parts of life for energy, for example forgoing school excursions, going without food or not paying rent, and generally curtail their wellbeing in other areas of life.

The extent of the impact varies depending on a range of factors such as the amount of energy that a customer uses, the energy prices they pay, their income and other living costs. For low income households, residential gas bills typically represent around 2.5–5 per cent of a disposable income (before any concessions).[111] The AER noted that gas affordability fluctuated markedly in 2016, with improvements in NSW (a fall in the share of low income households' disposable income of 0.3 percentage points), no change in Queensland and the ACT, and deteriorations in Victoria (a 0.4 percentage point increase) and South Australia (a 0.2 percentage point increase).[112]

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105 Australian Council of Social Service, Brotherhood of St Laurence, The Climate Institute, *Empowering disadvantaged households to access affordable, clean energy*, 2017,Victorian Minister for Energy, Environment & Climate Change, 7 June 2017 Media Release, *Real Reforms, Right Now To Reduce Gas Bills And Protect Job*s, http://www.premier.vic.gov.au/real-reforms-right-now-to-reduce-gas-bills-and-protect-jobs/

106 Oakley Greenwood, *Gas Price Trends Review*, 2015.

107 AER, *State of the Energy Market*, May 2017, p.133

108 AER, *AER draft decisions to propose stable gas network charges for Victoria and Albury,* 6 July 2017. Access here: https://www.aer.gov.au/news-release/aer-draft-decisions-to-propose-stable-gas-network-charges-for-victoria-and-albury

109 On 20 June 2017, the Australian government announced that it would abolish limited merits review of AER decisions. See https://www.pm.gov.au/media/2017-06-20/press-conference-hon-josh-frydenberg-mp-minister-environment-and-energy-and-senator

110 Australian Council of Social Service, Brotherhood of St Laurence, The Climate Institute, *Empowering disadvantaged households to access affordable, clean energy*, 2017, p.25

111 AER, *State of the Energy Market*, May 2017, p.147.

112 AER, *Annual Report on the performance of the retail energy market 2015-16*, pp. 50–72.

3.5. Gas Powered Generators as users of gas

GPG generate electricity from gas and supplies it to the National Electricity Market (NEM). GPG bids into the NEM at five minute intervals (dispatch interval) and is compensated according to the average price over each 30 minute interval (trading interval). Generation is dispatched according to merit order with the lowest bidding generators dispatched first. All generators receive the highest price that is bid by generators and which is actually dispatched. Therefore, the marginal supplier sets the price of electricity for each interval. The range of prices that can be bid into the NEM is large as generators can bid between –$1000 and $14 200 per megawatt hour (MWh). When demand is high, GPG is often the marginal generator and sets the wholesale electricity price.

The ACCC spoke with six different operators of GPG and reviewed information compulsorily acquired from a number of gas suppliers.

AEMO's short term estimates of GPG demand have fluctuated over 2017. AEMO's June 2017 Energy Supply Outlook (ESO) forecasts were higher than forecast in its March 2017 GSOO. The higher June 2017 forecast for GPG demand included greater gas usage by Pelican Point in South Australia and Swanbank E in Queensland following government announcements and recontracting.[113] The June ESO highlights overall a tightly balanced supply-demand forecast for the gas market continuing to be very susceptible to 'swing' in the amount of GPG demand. The tightness of the overall gas supply-demand balance creates a current and large interdependence in forecasts across gas and electricity markets, explaining AEMO's move to publish an ESO which looks at both markets together.

AEMO's forecasts this year for 2018 GPG gas use are also substantially lower than its longer-term forecast in 2015. Information provided to the ACCC indicates that consistent with AEMO considerations, a number of GPGs responded in the last five years to lower future forecast NEM prices and concerns around competitiveness between renewables and coal, by changing supply contracts to move away from an 'intermediate' generation strategy to a more peaking role. Part of this strategy was also to sell gas to export projects where this was held in portfolios. Now that higher NEM prices are forecast for 2018, these strategies appear to be being revised.

To offer electricity into the NEM, a generator must have enough gas available and must also have transportation arrangements in place to ensure it can generate the amount of electricity offered. Gas used for electricity generation in eastern Australia is sourced in a variety of ways by the different operators, and the gas sourcing approach plays a significant role in the operating strategy of the plant. Some GPG operators are vertically integrated, with ownership of gas resources and many combine gas generation with gas retailing activities, allowing them to take a portfolio view of gas flows and costs. These generators have more flexibility in how and when they run their gas plants.

Similarly, other generators have long-term GSAs that have electricity price hedges aligned with their GSAs. These operators are constrained less by prices, and more by their contracted gas supply quantities and their electricity supply commitments.

There are also a number of GPG who source gas from upstream and downstream spot markets. These operators buy gas when the electricity price is likely to be high enough to cover the input gas costs, or the 'spark spread' between gas and electricity prices. These plants tend to run as peaking plants during high electricity demand periods. However, generators with contracted electricity output can also operate in this manner by increasing output above contracted amounts at times to take advantage of the spark spread. This strategy relies on the availability of gas and the ability to transport it when it is needed.

[113] AEMO *Energy Supply Outlook*, 15 June 2017, AEMO Gas Statement of Opportunities, March 2017.

As electricity generated from gas when electricity prices are high can be expected to recoup input costs even at higher gas prices, GPG operators can experience less risk and price exposure compared with other gas users. For example, in mid-February 2017, Wallumbilla gas prices increased above $10/GJ when Queensland electricity market prices spiked above $5000/MWH across 30-minute periods.[114] Some GPG also have more flexibility in when they run and many have alternative fuel sources available. Gas generators on the whole appear to have a slightly more advantageous market position compared with many industrial and residential gas users, because they have greater capacity to bear higher gas prices and less flexible supply conditions.

As gas prices rise, gas storage is becoming increasingly important for GPG, because it enables them to hedge against prices or minimise costs and it also ensures supply is available when it is needed. While some GPG utilise traditional underground or LNG storage, others use pipeline capacity instead (referred to as 'linepack'). For example, Snowy Hydro's Colongra Power Station in NSW uses its specially designed gas transportation pipeline to store enough gas to allow the power station to run at full capacity for five hours.[115] Other GPG are able to use the linepack available on certain pipelines as storage, to quickly access gas when needed, albeit at a premium price.

The lack of transparency around linepack availability and tradeable value has, however, been a barrier to more efficient use of linepack for electricity generation. One user said that the excessive prices for pipeline storage charged by one pipeline operator often made it uneconomic to take advantage of lower gas spot prices for use during peak NEM periods. The intermittency of the operation of peaking generators means that flexible gas supply, transportation and storage options are critical.

These issues of transport and storage will be examined in a future report of this Inquiry.

3.5.1. Access to affordable gas is critical for electricity market affordability

The rising cost of gas is also one of the likely drivers of Australia's current electricity affordability issues. Dr Finkel's *Blueprint for the Future* highlighted securing adequate and affordable gas supply as one element required to maintain security and reliability in the NEM.[116] GPG is increasingly the marginal source of generation, which means that gas is often setting dispatch prices, especially when demand is high. Competition between generators, and particularly GPG who can lift output at times of peak demand, will be important in constraining wholesale prices. GPG is now the only source of dispatchable power in SA. In this context, it is worth noting that electricity prices spiked over summer 2016–17 in South Australia and Queensland without Swanbank E being in the market and also Pelican Point only operating at partial capacity.[117] These generators will be available for summer 2017–18.

Some GPG have secured gas supply for 2018, and others are in the process of attempting to secure supply or will rely on accessing the short-term trading gas markets.

The availability and reliability of gas supply is a greater concern for GPGs that do not have long-term supply contracts. One generator told the ACCC that it had not been able to secure

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[114] AER, *Wallumbilla Gas Supply Hub - trade volume and VWA prices by product*: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/wallumbilla-gas-supply-hub-trade-volume-and-vwa-prices-by-product, AER, *Weekly volume weighted average spot prices*: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/weekly-volume-weighted-average-spot-prices

[115] Jemena, *Colongra Gas Transmission and Storage Pipeline*: https://jemena.com.au/industry/pipelines/colongra-gas-transmission-and-storage-pipeline

[116] *Independent Review into the Future Security of the National Electricity Market*, Chapter 4.

[117] AER, *Quarterly volume weighted spot prices:* https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-volume-weighted-average-spot-prices

a gas deal for the second half of 2017 or 2018 despite seeking offers from the market on a number of occasions, and was sourcing gas from spot markets instead. The generator has traditionally been able to secure summer gas contracts (when it tends to run most) that have enabled it to write electricity market derivative products. It advised that difficulties in securing gas supply for 2018 were creating challenges in managing forward positions and could adversely impact its ability to generate electricity over the coming summer peak demand periods.

When seeking offers for gas supply for 2018, one GPG reported unfavourable negotiating conditions similar to those reported by other large gas users. It stated that

> the market is highly illiquid and opaque, and is a seller's market – it is always the buyers who have to first approach the sellers and specify their requirements, and often multiple follow ups (extending over several weeks or in some cases, months) are required to obtain a seller response.

This makes it hard for GPG to assess market conditions before determining their forward operating strategy and supply requirements.

GPG users have also had to look at options for securing gas other than through directly negotiated supply contracts, including taking part in a number of the EOI processes that were run in the first half of 2017. The ACCC has also found that some LNG producers dispose of excess gas during planned and unplanned maintenance to GPG (including their own) directly or via spot markets, in combination with other strategies. This has been associated with increased instances in Queensland of gas being available to the market for short-term periods rather than long-term supply contracts sought by GPG (and other consumers).

Similarly to industrial gas users, gas transportation costs, availability of pipeline capacity and lack of transparency are cited to the ACCC as barriers to efficient market competition for gas supplies. Where possible, GPGs say they engage in gas swaps to avoid having to physically transport gas and incur excessive transportation costs.

GPGs are responding to higher gas prices and tightening supply in a number of ways. Many generators have diverse portfolios of complementary generation assets like coal, hydro or renewables enabling them to run on whichever fuel source is more economic at the time. About a quarter of the GPG capacity in the NEM is capable of operating on a secondary fuel, given sufficient notice of requirement.[118] This gives operators additional flexibility when deciding if and when to consume gas.

In the past, some operators have opted to withdraw capacity in response to higher gas prices. A prime example is Stanwell's withdrawal of the Swanbank E Power Station in Queensland because it could earn more revenue from selling its gas rather than using it to generate electricity.[119] Similarly, one of Engie's two units at the Pelican Point power station in SA was mothballed due in part to high gas prices relative to electricity prices, along with the need for capital reinvestments.[120] It took intervention from the respective Queensland and SA governments in 2017 to return both power stations to operation. Stanwell is currently sourcing gas to enable Swanbank E to return to service from the first quarter of 2018, announcing a deal on 6 September with Shell for supply for 2018[121]. Engie has entered into

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118 AEMO, Energy Supply Outlook, June 2017, p.18.

119 Stanwell, *Swanbank E Power Station*: http://www.stanwell.com/energy-assets/our-power-stations/gas/

120 Information provided to the Inquiry.

121 http://statements.qld.gov.au/Statement/2017/9/6/stanwell-and-shell-seal-the-deal-for-swanbank-e-gas-supply

gas supply deals with Origin[122] to 2020, with Shell for winter 2017[123] and with Santos starting in January 2018.[124]

The returned full or near full capacity of these power stations is expected to contribute to meeting reliability standards in the NEM in time for summer 2017–18.[125] The publicly-controversial decisions of these GPGs not to operate are evidence of the flexibility that generators have when making operating decisions based on gas cost and availability.

Consistent with recent developments in negotiations of industrial users, some GPGs have reported increases in the number of suppliers making genuine offers since June 2017, with some reporting offers of supply for longer-term periods. Should this continue, the contribution of existing GPG capacity to the NEM could increase in 2018.

In the short to medium term, the NEM is likely to require higher levels of flexible GPG to maintain security and reliability. However, in the current environment there appear to be few incentives for investing in new GPG, with the exception of government-led investment as seen in South Australia[126] and AGL, which has announced plans to replace its ageing generating units at its Torrens Island generator with newer more efficient generating units.[127] Gas supply uncertainty and price volatility, lack of transparent market information, as well as barriers to efficient transportation and storage, may be impediments to future investment in GPG. As coal-fired generators retire, GPG is likely to set the marginal cost of generation within the NEM more often, which will flow through to consumers as higher retailer electricity prices. Under these circumstances, access to affordable gas supply will be critical.[128]

Gas Supply Guarantee

In March 2017, gas producers and pipeline operators made commitments to the Australian government to make gas supply available to GPG in times of peak NEM demand periods, such as during heat waves. An AEMO Industry working group has developed the Peak Electricity Demand - Gas Supply Guarantee (GSG) mechanism to facilitate the delivery of these commitments in time for summer 2017/18.[129] The mechanism will be documented in a participation guideline rather than through legislation and rules.

The ACCC understands that generators welcome the mechanism, but are sceptical of its potential to ensure gas is available to meet peak demand due to the non-binding nature of the participant agreement. Market participants noted that access to pipeline capacity to transport gas to power stations in time for a peak demand period is critical and pipeline operators must be part of the solution.

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122 Origin Energy, *Origin works with Engie to help boost energy security in South Australia*, 29 March 2017: https://www.originenergy.com.au/about/investors-media/media-centre/origin-works-with-engie-to-help-boost-energy-security-in-south-australia.html

123 Shell Australia, *Shell seals more east coast domestic gas deals,* 6 April 2017: http://www.shell.com.au/media/2017-media-releases/shell-seals-more-east-coast-domestic-gas-deals.html

124 Santos, 14 August 2017, *Santos to redirect gas to South Australian economy*: https://www.santos.com/media-centre/announcements/santos-to-redirect-gas-to-south-australian-economy/

125 AEMO https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Energy-Supply-Outlook.pdf

126 http://ourenergyplan.sa.gov.au/

127 ABC News, AGL anncounces plans for new gas-fired power station in South Australia, 7 June 2017: http://www.abc.net.au/news/2017-06-07/agl-announces-new-sa-power-station/8596016

128 *Independent Review into the Future Security of the National Electricity Market*, p. 105.

129 AEMO *National Electricity Market Wholesale Consultative Forum*, Meeting Pack August 2017 – https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Wholesale-meetings/NEM-Wholesale-Consultative-Forum

3.6. Access to pipeline and storage capacity

In addition to difficulties securing gas on reasonable terms, the ACCC found in its previous inquiry, evidence of monopoly pricing on a large number of transmission pipelines that was adversely affecting economic efficiency.[130] The ACCC heard that many of these issues are still being experienced with market opacity resulting in buyers being unable to evaluate the competitiveness of transport costs passed on to them, and unable to identify which pipelines are fully utilised. Users of transportation services said that they have to accept whatever rates are offered, even if they think the costs are excessive, due to a lack of alternatives.

In its previous inquiry, the ACCC heard complaints of retailers withholding capacity on some smaller regional pipelines where the retailer had contracted all the capacity.[131] This puts industrial users at a disadvantage when negotiating gas supply, potentially restricting competition from other suppliers.

Since the ACCC's previous inquiry report was released, the Australian government has initiated a range of reform measures to encourage efficient gas transportation. While it is too early to assess the effects that these reforms will have on gas transportation arrangements, some users have reported better terms in negotiations for pipeline services in the past year. However, many users of pipeline transportation are unconvinced that the current transportation reforms will lead to long-term sector efficiencies and competitive prices, and they have renewed calls for full regulation of all transmission pipelines.

The ACCC will continue to investigate and monitor issues in the gas transportation sector and will report more fully on these issues in subsequent Inquiry reports.

[130] ACCC, *East Coast Gas Inquiry 2015*, April 2016, p. 8.

[131] ACCC, *East Coast Gas Inquiry 2015*, April 2016, p. 15.

4. East Coast Gas Market price outlook for 2018

4.1. Key points

- Gas prices in the East Coast Gas Market have increased significantly over the past year.
- Average daily prices in Queensland on the Brisbane short-term trading market (STTM) and Wallumbilla Gas Supply Hub in the second quarter of 2017 were $8.20/GJ and $7.23/GJ (respectively), which are 62 and 53 per cent increases on these averages for the first quarter of 2016.[132]
- Average daily prices in the Victorian, Sydney and Adelaide spot markets in the second quarter of 2017 were $9.52/GJ, more than double the average price for the first quarter of 2016.
- In Queensland, wholesale (ex-plant) gas prices agreed between gas users and producers under new contracts for 2018 supply since the start of 2016 (of which there have been four) have averaged around $7.33/GJ (volume weighted).
    - These prices are above those currently being paid and are above what the ACCC considers to be an appropriate benchmark price in Queensland for 2018.
    - The level of prices agreed under recent contracts in Queensland suggests that there may not have been effective competition between Queensland producers over this period.
- In the Southern States, three contracts have been entered into for 2018 supply with producers in off-shore Victoria since the start of 2016, with agreed wholesale gas prices averaging around $7.29/GJ (volume weighted).
    - However, there is significant variation in prices charged by the Victorian producers, with the most recent price agreed towards the end of 2016 being above what the ACCC considers to be an appropriate benchmark price range for 2018 in the Southern States.
- With the addition of transportation costs from production areas to the major demand centres, the delivered wholesale price of gas in Queensland and the Southern States would be between $0.37–1.25/GJ higher than ex-plant prices, depending on the source of supply and the user's location.[133;134]
- Prices agreed for 2018 supply do not, however, provide a full picture of the market. A number of commercial and industrial (C&I) users are deferring agreeing to contracts for 2018 supply and beyond due to the high price of offers. Unfulfilled price offers increased sharply between late 2016 and early 2017, ranging between $10–16/GJ over this period – significantly above the ACCC's view of a benchmark price.
- The level of recent gas prices and gas price offers for 2018 indicates that gas suppliers expect a supply shortfall in the East Coast Gas Market in 2018.
- To the extent that the Queensland liquefied natural gas (LNG) projects have excess gas for 2018, this could be sold onto international LNG spot markets or to domestic users. Comparison of agreed domestic gas prices and recent unfulfilled offers for 2018 with

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132 These quarters have been compared (rather than year-on-year) because of volatility in the spot markets between mid-2016 and early 2017 (see section 4.2.3).

133 The recently executed producer contracts discussed in this chapter are mostly with users close to the source of production, so the cost of transportation for these users will be at the lower end of this range.

134 This is an indicative range based on the transmission tariffs that were reported in the previous inquiry, which have been escalated by CPI.

LNG netbacks based on forecast 2018 Asian LNG spot prices suggests that it is likely to be more commercially attractive for the LNG projects to sell gas domestically.

4.2. Gas prices paid in the East Coast Gas Market in 2016 and 2017

In the ACCC's previous inquiry, users raised concerns about the lack of transparency relating to wholesale gas prices and the effect this has on their ability to negotiate effectively with producers and retailers when entering into a new gas supply contract. To address these concerns, the ACCC's previous inquiry recommended a number of price transparency measures, including the publication of a volume weighted wholesale gas price series that would be calculated using the prices and volumes actually invoiced by producers.[135]

Consistent with this recommendation, the ACCC has developed a quarterly producer-based invoiced gas price series and intends to update and publish this periodically over the course of the current Inquiry. The ACCC has also developed a retailer-based invoiced gas price series, that has been calculated using the prices and volumes charged by retailers to C&I gas users.[136]

As the ACCC's previous inquiry noted, the publication of an invoiced price series is expected to:[137]

- reduce the degree of information asymmetry faced by users and pose a clearer competitive constraint on producers and retailers during supply negotiations; and
- provide producers with clearer signals about the need to develop new gas supplies.

While there are some clear benefits to publishing the invoiced price series, it is important to note that the price series presented below reflect all gas supply contracts with a term of one year or more that are on foot in a particular quarter. It therefore includes the prices payable under a number of legacy contracts that were entered into prior to the development of the LNG facilities in Queensland and the consequent shift in demand and supply conditions in the East Coast Gas Market over the past five years. The prices seen in the invoiced price series are therefore lower than the prices that have been agreed more recently (see section 4.3.3) and that are currently being offered in the market (see section 4.3.4).

4.2.1. Gas prices paid under long-term gas supply agreements

Chart 4.1 shows the quarterly volume weighted average price[138][139],that gas users (including retailers, C&I users, gas-powered generators (GPGs), LNG producers and other users) paid to gas producers in the Surat/Bowen, Cooper and Victorian basins in 2016–17.

The average prices in the chart have been calculated using unit prices specified in invoices issued by producers over this period under bilateral gas supply agreements (GSAs) entered into on an arm's length basis for a term of one year or more. It is important to note that prices under bilateral GSAs are influenced by non-price terms and conditions, including load factor, take or pay level, capacity commitments and contract length. The ACCC has not sought to account for these in this report, but may seek to do so in future interim reports.

The prices 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 users' end location.

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135 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 87-91.

136 Note that this price series only focuses on prices charged by retailers for gas (sometimes referred to as 'energy' in the invoices) and not the transportation and other ancillary charges levied by retailers.

137 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 89.

138 The weights used in the calculation of the weighted average price are based on the actual volumes of gas supplied in the relevant period.

139 The prices appearing in this chart exclude spot sales, seasonal contracts and related party transactions.

The cost of transportation has been excluded from this analysis to enable a more direct comparison between the prices charged by producers in each basin with the LNG netback price (discussed in section 4.3.1).

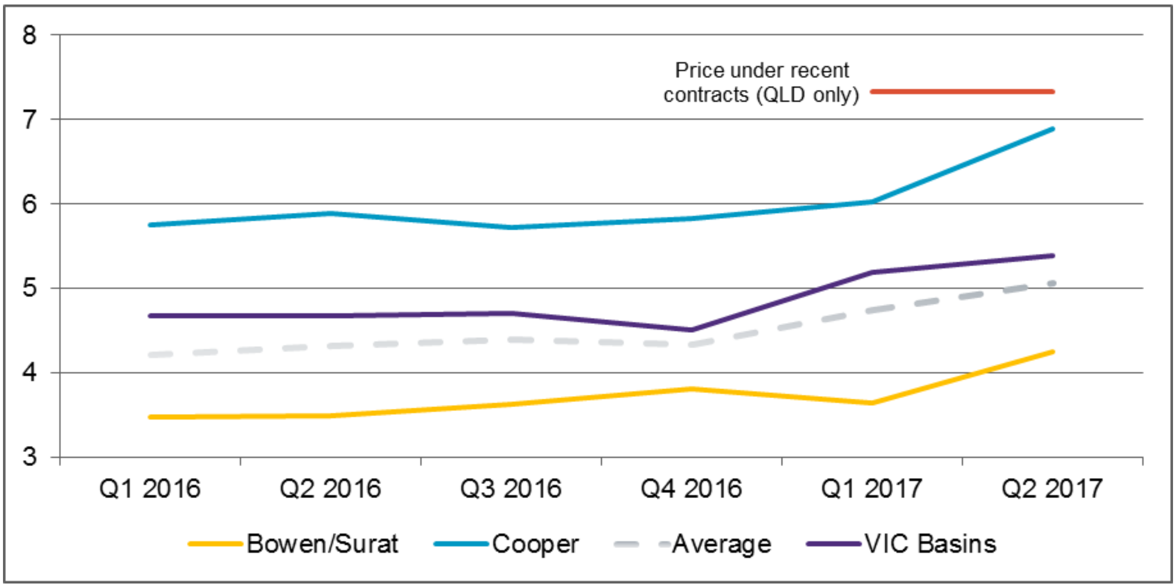
Given the small number of producers in each basin in Victoria, a single volume-weighted average price has been calculated for Victoria, which reflects the prices charged by producers in the Otway, Bass and Gippsland basins. The Queensland average price reflects the prices charged by producers in the Surat and Bowen basins that are capable of supplying gas to Wallumbilla. The Cooper Basin price reflects the prices charged by three suppliers.

As noted above, the averages presented in chart 4.1 below encompass the invoiced prices of all contracts on foot in a particular quarter and therefore include prices paid under both legacy contracts and newer contracts. Gas users currently seeking to contract for gas, are likely to pay prices higher than indicated below. The average price paid under contracts recently entered into (since 2016) has been separately marked on the chart. The recently executed contracts under which supply commenced in 2017 are in Queensland.

The average price paid under Surat/Bowen contracts on foot at the start of 2016 was \$3.48/GJ, while the average price paid under recently executed contracts at the start of 2017 was \$7.33/GJ – a 110 per cent increase.

Producer prices have increased by around 17 per cent on average over the period between 2016 to the second quarter of 2017. Most of this increase occurred after the fourth quarter of 2016. The increase in producer prices is broadly based, occurring across all of the major east coast regions.

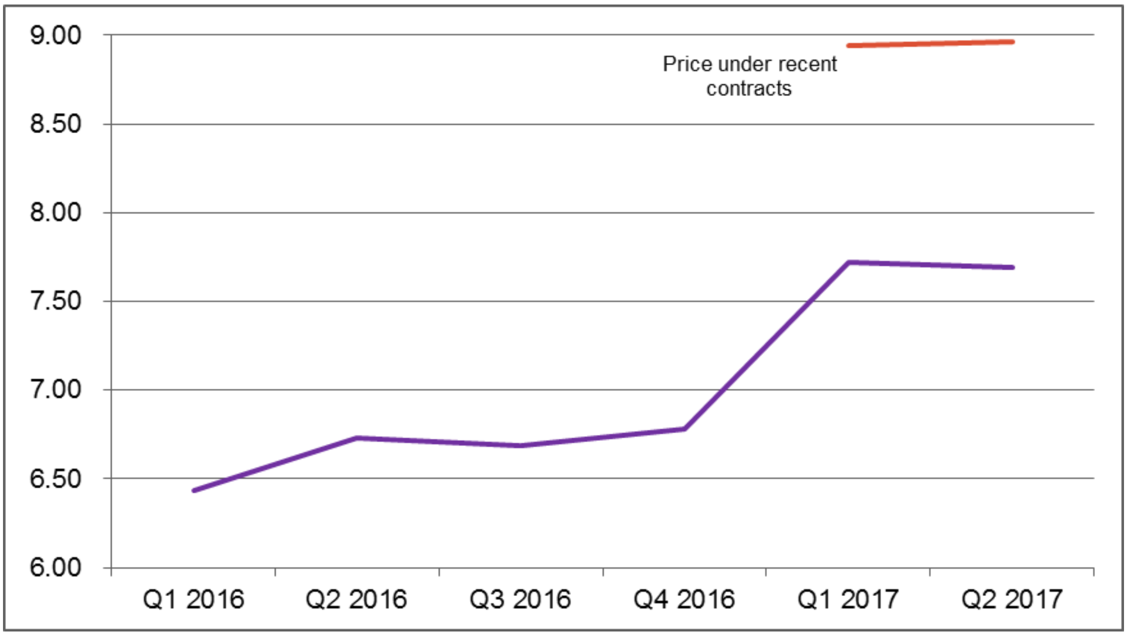
Chart 4.1: Producer commodity gas prices by basin (\$nominal/GJ)



Source: ACCC analysis based on information received from producers

In addition to examining the prices paid to producers, the ACCC also examined the prices that C&I users paid to retailers in 2016–17. Volume weighted average prices are shown in chart 4.2 below and, as with the producer prices, are based on the wholesale price of gas excluding transportation and other ancillary charges.

Chart 4.2: Retailer prices, average for the East Coast Gas Market (\$nominal/GJ)



Source: ACCC analysis based on information received from retailers

C&I users were charged more for gas by retailers at the end of this period than they were at the beginning of 2016. Average retailer prices across the East Coast Gas Market have increased by around 20 per cent over this period. Similar to producer price increases, the majority of the price increase occurred after the fourth quarter of 2016.

The average price paid under contracts entered into with retailers since the start of 2016 has been separately marked on chart 4.2. The average price paid under retailer contracts on foot at the start of 2016 was $6.43/GJ, while the average price paid under recently executed contracts at the start of 2017 was $8.94/GJ – a 39 per cent increase.

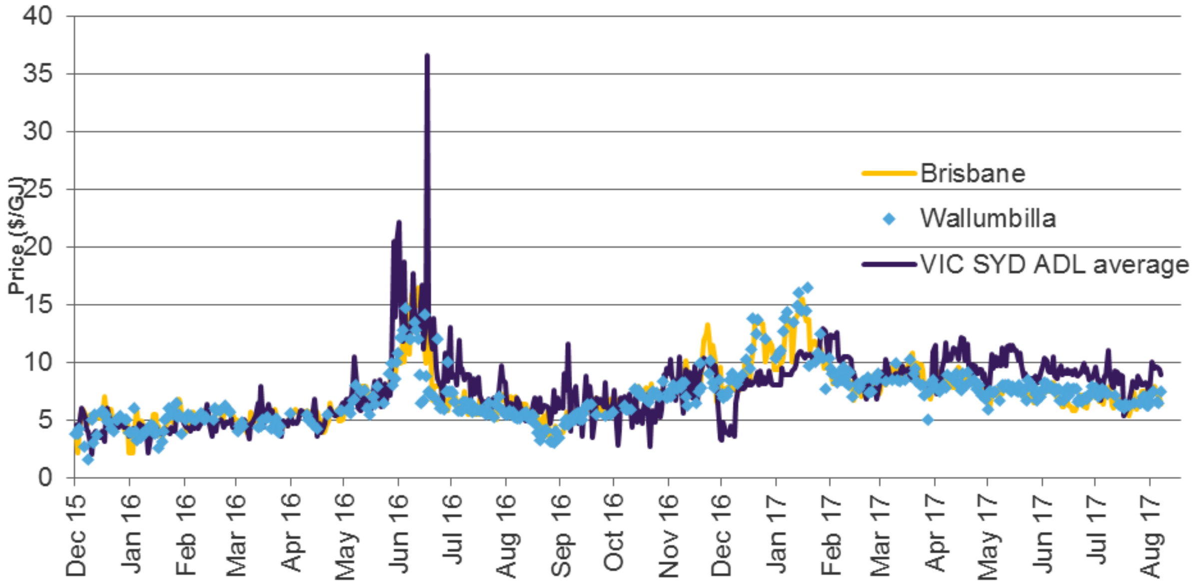
4.2.2. Gas prices paid under short-term gas supply agreements

Information provided to the ACCC identified over 20 petajoules (PJ) of gas sales under short-term GSAs for 2017 by LNG exporters with durations typically designed to align with the east coast winter. There were a number of these GSAs, and prices averaged over $9/GJ. In striking these deals, favourable comparisons were made by the sellers to LNG spot price outcomes if, alternatively, this gas was to be exported. Businesses considered they were able to obtain higher margins above Asian LNG spot prices of around $2–4/GJ.

4.2.3. Gas prices paid in domestic short-term trading markets

Chart 4.3 shows the daily prices in the Brisbane STTM and the Wallumbilla Gas Supply Hub in Queensland from the end of 2015 to August 2017, as well as the volume weighted average price in the Sydney and Adelaide STTMs and the Victorian declared wholesale gas market.

Chart 4.3: Daily prices paid in domestic short-term trading markets – December 2015 to September 2017



Source: ACCC analysis of AEMO data

Daily prices on these domestic spot markets have increased significantly since the end of 2015. Although there was a period of high volatility from winter 2016 to summer 2017 due to transitory factors (such as higher than expected winter demand from GPGs, field outages in Queensland, depletion of southern storage and increased LNG production after the commissioning of APLNG's second train), spot prices have been largely consistent for the majority of 2017.

The average price in the second quarter of 2017 for the Victorian, Sydney and Adelaide markets was $9.52/GJ, more than double the average price of $4.41/GJ for the first quarter of 2016. Increases are also observed in Queensland over the same period, both on the Brisbane STTM (from $5.06/GJ to $8.20/GJ) and at the Wallumbilla Gas Supply Hub (from $4.73/GJ to $7.23/GJ).

4.3. Gas prices and gas supply offers in the East Coast Gas Market for 2018

This section presents the ACCC's findings on producer and retailer prices agreed under contracts for 2018 gas supply that were executed in the period between January 2016 and May 2017. It also presents findings on unfulfilled offers for gas supply in 2018 that were made over the same period.

Prices that are expected to be paid in 2018 under producer contracts (using assumptions about foreign exchange rates, oil prices and consumer price index (CPI), where relevant) are compared to relevant price indicators and appropriate benchmark prices for 2018.

The ACCC has not compared prices under the retailer contracts with benchmark prices because prices charged by retailers may include retailer specific gas supply costs and retailer margins.

4.3.1. Relevant price comparators

With the East Coast Gas Market now linked to the world LNG market, domestic gas prices are expected to be shaped by the prices that the east coast LNG projects are able to achieve for their exports. These prices will, in turn, depend on whether cargoes are sold under long-term export contracts or on the international LNG spot market.

If cargoes are sold under long-term export contracts, the price that would be achieved by the exporter will be the price agreed under the relevant contract.[140] If, for example, an LNG exporter were deciding whether to sell its own upstream production as part of a long-term export contract or to the domestic market, the minimum price it would need to receive to sell domestically would be the LNG contract price less the short-run costs associated with shipping and liquefaction (the LNG contract netback). Alternatively, if an LNG exporter were buying domestic gas to meet its long-term export contract commitment, it may be willing to pay up to the LNG contract netback.

On the other hand, if cargoes are sold into the international LNG spot market, the price that would be achieved by the exporter would be the relevant LNG spot price. If an LNG exporter were deciding whether to sell its upstream production into the international LNG spot market or to the domestic market, the minimum price it would need to receive to sell domestically would be the LNG spot price less marginal shipping and liquefaction costs (the LNG spot netback).

Which of the LNG contract or spot netback is the most relevant comparator to inform expectations about prices and the level of competition in the domestic market at a given time depends on range of factors, which the ACCC canvassed in its previous inquiry. For example, it can depend on whether the LNG projects in aggregate have sufficient gas supply to meet minimum export contract obligations, and also which of the LNG netbacks is higher.

The ACCC has estimated LNG contract and spot netbacks for 2018. Current market expectations are that 2018–19 Asian LNG spot prices will average around US$6/MMBtu[141], as noted by EnergyQuest.[142] This price equates to AU$7.17/GJ.[143] Subtracting the average marginal cost of liquefaction and shipping (estimated by the ACCC based on aggregated information obtained from the three Queensland LNG projects) gives an LNG spot netback of AU$5.87/GJ.

The ACCC notes that market expectations about the Asian LNG spot prices have been fairly consistent over the past 18 months. Information provided by producers and exporters indicates that since the start of 2016 businesses have taken a view that Asian LNG spot prices would remain at low levels in the short to medium term. This is consistent with the Office of the Chief Economist's *Resources and Energy Quarterly* findings from the start of 2016.[144]

Using the pricing mechanisms in long-term export contracts provided by the Queensland LNG projects to the ACCC, and assumptions about oil prices, foreign exchange rates and CPI, the ACCC has estimated expected contract prices across each LNG project's export contracts for 2018. Subtracting the average marginal cost of liquefaction and shipping costs, gives an average LNG contract netback of $8.00/GJ.[145]

140 The LNG projects' long-term export contracts are oil-linked, with some also including fixed price components.

141 Million British Thermal Units.

142 EnergyQuest, *EnergyQuarterly*, September 2017, p. 63.

143 Based on conversions of: AU$1 = US$0.79, 1 MMBtu = 1.055 GJ.

144 Office of the Chief Economist, *Resources and Energy Quarterly*, March 2016.

145 This estimated LNG contract netback accounts for any differences in LNG delivery arrangements, i.e. DES or FOB. Estimates of liquefaction and shipping costs are subtracted from contract prices only where relevant.

4.3.2. Benchmark prices for producers for 2018

As discussed in chapter 2, the LNG projects in Queensland expect to have sufficient gas to meet their contractual export commitments for 2018, and have additional gas that could be sold on the international LNG spot markets (which are likely to be the Asian LNG spot markets). In these circumstances, the ACCC considers that the most relevant price comparator for informing expectations about prices and the level of competition in the domestic market for 2018 supply would be the LNG spot netback, rather than contract netback. Material provided to the ACCC indicates that major east coast producers and the Queensland LNG projects generally view LNG spot prices as being the relevant comparator with which to assess domestic prices.

For Queensland producers to be willing to supply domestic users, they will need to receive a price for their gas that is at least equal to the opportunity cost of exporting the gas as LNG or the cost of producing it (whichever is higher).

The ACCC has considered material relating to production costs provided under its previous inquiry and more general information provided under this inquiry. This material indicates that, among the east coast LNG projects, the cost of production of newer Queensland CSG fields is currently expected to be $5-6/GJ at the wellhead. The ACCC acknowledges, however, that more recent assessments of the cost of production in Queensland may be above this level, which if above the expected LNG spot netback, would be the minimum price at which a Queensland producer would be willing to supply.

Given the similarity between the upper end of this range and the ACCC's estimated LNG spot netback for 2018 at Wallumbilla, the ACCC considers that it is appropriate to use the LNG spot netback at Wallumbilla as the benchmark to assess the LNG projects' willingness to supply.[146] Therefore, Queensland producers would need to receive at least $5.87/GJ from domestic buyers to be willing to supply them (all else being equal).[147]

The ACCC considers that an appropriate benchmark price would be one where producers are able to generate the same value as they would if the gas were sold for export, and at a minimum are able to recover their costs of production and an economic return on their investment.

In a well-functioning market, buyers in Queensland would expect to pay to producers a wholesale price based on the LNG spot netback. An appropriate benchmark price with which to compare wholesale prices charged by Queensland producers would be the LNG spot netback in Queensland – that is, $5.87/GJ.

As explained above, this is an ex-plant price that does not include the cost of transporting gas to the users' end location. The delivered price actually paid by each gas user would then depend on the cost of transporting gas from the wellhead to the user's location.

This is particularly critical for domestic buyers in the Southern States. Given the currently expected supply-demand balance for 2018 indicates a supply shortfall in the Southern States, domestic gas buyers in the Southern States would need to contract with Queensland gas producers to meet their gas needs, and would be expected to bear the cost of transporting the gas from Queensland (or the Cooper Basin) to their location.

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146 The ACCC notes that, depending on the producer, there may be additional costs beyond costs of production at the wellhead that would need to be taken into account which may vary across exporters – for example any pipeline tariffs that are payable between the wellhead and APA's Wallumbilla compound connecting to the SWQP.

147 The LNG projects do not all have the same costs of production, and some may have cheaper costs of production associated with new field developments. EnergyQuest for example notes at page 63 of its EnergyQuarterly September 2017 that it should be profitable for 2 of the LNG projects to sell spot cargoes at (Asian) spot prices over US$5/MMBtu, suggesting local costs of production closer to $5/GJ.

The ACCC estimates that, on the basis of the transportation costs of major transmission pipelines estimated during its previous inquiry and information obtained under this Inquiry, the average cost of transportation in 2018 from Wallumbilla is: $1.66/GJ to Adelaide, $2.00/GJ to Sydney and $2.26/GJ to Melbourne.[148] Adding these transportation costs to the estimated LNG spot netback gives a total delivered price of $7.54/GJ for Adelaide, $7.87/GJ for Sydney and $8.14/GJ for Melbourne.[149]

In a well-functioning market, a market price of gas at a particular location would be shaped by the alternatives available to both buyers and sellers of gas. As explained earlier, gas from the Queensland producers is an important alternative source of supply for buyers in the Southern States. Therefore, the delivered price of gas from Queensland to the Southern States 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 user's location, less the cost of transporting the gas from the producer's wellhead to the user's location. For example, in a well-functioning market, a producer located in Victoria selling gas to a domestic gas user in Sydney would expect to receive a price at their wellhead of $7.87/GJ less the cost of transporting gas from Victoria to Sydney.

Therefore, the ACCC is of the view that an appropriate benchmark price with which to compare wholesale prices charged by producers in the Southern States would be the LNG spot netback in Queensland plus the cost of transportation from Queensland to the user's location in the Southern States, less the cost of transportation from the producer's wellhead to the user's location.

Almost all of gas production in the Southern States is currently being served by gas producers in off-shore Victoria. Based on information obtained in its previous inquiry, the ACCC estimates that the cost of transporting gas from off-shore Victoria to Melbourne, Sydney and Adelaide is typically $0.37-1.25/GJ.[150]

Therefore, a benchmark price that producers in the Southern States would be expected to receive at the wellhead would be the delivered prices of Queensland gas in the Southern States (being $7.54/GJ in Adelaide, $7.87/GJ in Sydney and $8.14/GJ in Melbourne) less an amount to account for transportation $0.37-1.25/GJ, depending on the user's location.

[148] The ACCC's estimates of transport costs assume that gas location swap arrangements are able to be utilised between Queensland CSG fields and the Cooper Basin, which could facilitate supply from the Cooper Basin to the Southern States (under contracts with Queensland producers) while avoiding the transportation costs of the SWQP.

[149] Note that the LNG spot netback with transport costs added may slightly differ to these delivered prices due to rounding.

[150] These transportation cost estimates are based on information obtained in the previous inquiry and include an allowance for pipeline losses. The tariffs have also been calculated assuming a 100 per cent load factor.

Box 4.1: How prices in the Southern States could change with increased supply and diversity of suppliers in the Southern States

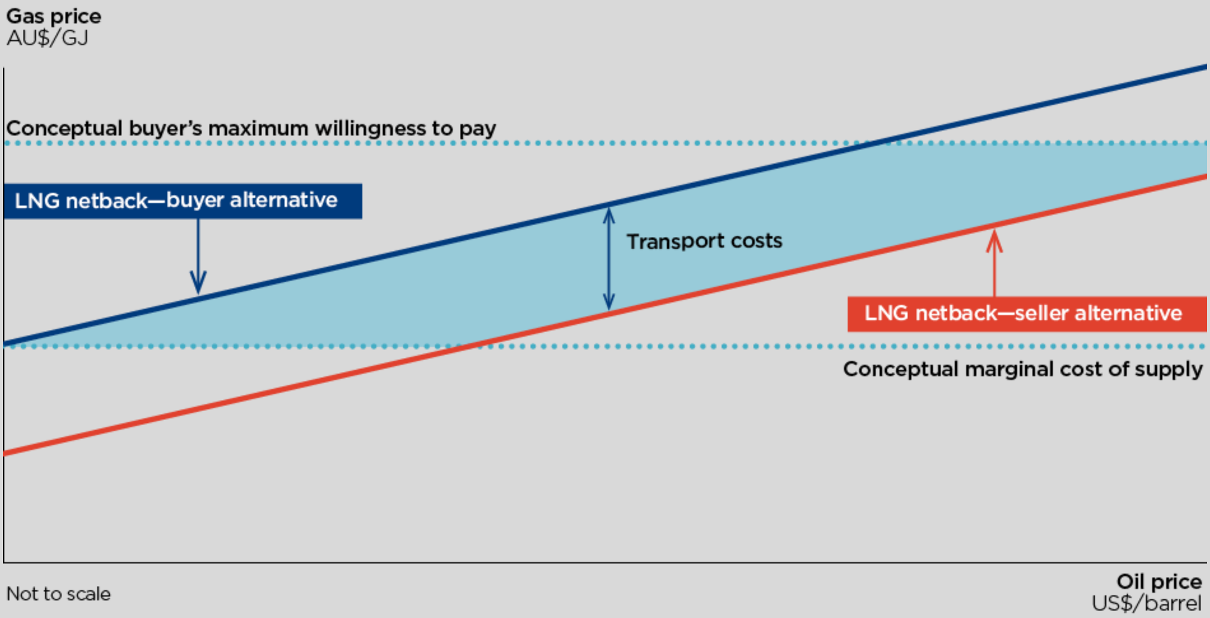
In its previous inquiry, the ACCC set out a bargaining framework to illustrate how gas supply negotiations in the Southern States may be influenced by the LNG fundamentals in Queensland.[151] This framework was based on the market conditions that existed at the time, when gas producers in the Southern States could meet domestic demand from their own production without requiring gas from Queensland.

The ACCC observed that, in those circumstances, while prices in the Southern States were likely to be shaped by LNG netbacks, the cost of transporting gas to, or from, Wallumbilla meant that there was a range of potential pricing outcomes:

- If there is diverse supply and strong competition in the Southern States, competition will drive suppliers in the Southern States to offer a price closer to their next best sales alternative. If this alternative is to sell gas to the LNG projects in Queensland, the price that the supplier in the Southern States would receive is the LNG netback price at Wallumbilla less the cost of transporting gas (and processing costs) to Wallumbilla (**the seller alternative**).
- If there is a lack of supply options in the Southern States and producers can set prices in the absence of competitive constraints from other producers in the Southern States, then these producers in the Southern States can charge a price approaching the buyer's next best alternative. If this alternative is to buy gas from producers in Queensland, the price that a gas buyer would have to pay is the LNG netback price at Wallumbilla plus transport costs from Wallumbilla to the buyer's location (**the buyer alternative**).

This is illustrated in chart 4.4.

Chart 4.4: Bargaining framework for gas supply negotiations in the Southern States



Note: This chart presents a stylised bargaining framework. The prices achieved by parties in individual negotiations will vary. Prices under bilateral GSAs are also influenced by the specific non-price terms and conditions agreed by the parties.

The gap between the buyer and seller alternatives consists of two components—the cost to the buyer of transporting gas from Wallumbilla to their location plus the cost to the seller of transporting gas from the buyer's location to Wallumbilla, including processing at Moomba and gas losses. The buyer's maximum willingness to pay and the marginal cost of supply in this chart are purely illustrative.

As set out in section 4.3.2, given an expected supply shortfall in the Southern States for 2018, gas prices in the Southern States are currently shaped by the buyer alternative. However, if additional supply is brought on in the Southern States that eliminates the southern shortfall and increases the level of competition between producers in these states, this could put significant downward pressure

[151] ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 50-53

on prices in the Southern States as producers would have to offer a price closer to the seller's alternative.

Table 4.1 shows the ACCC's estimates of the buyer and seller alternatives in Victoria for 2018.

Table 4.1: LNG netback and seller/buyer alternatives in Victoria, 2018 est.

Price/description	Buyer/seller
Asian LNG (delivered) spot price[152]	US$6.00/MMBtu
Delivered LNG price converted to AU$/GJ[153]	AU$7.17/GJ
Gladstone FOB price (subtract shipping costs and losses)[154]	AU$6.57/GJ
LNG netback at Wallumbilla (subtract liquefaction costs)[155]	AU$5.87/GJ
Indicative delivered gas price in Victoria based on LNG netback:[156]	
– Seller alternative (subtract transportation costs)[157]	AU$2.95/GJ
– Buyer alternative (add transportation costs)[158]	AU$8.14/GJ

Given the cost of production in the Southern States is likely to be higher than the estimated seller alternative of $2.95/GJ, the cost of production would set the floor in the negotiations between gas buyers and producers in Victoria.

The bargaining framework demonstrates that there are significant gains that could be achieved from improving the state of competition in the Southern States. The extent of these gains would depend on the cost of production of new gas supply. However, the ACCC considers that increasing the level of supply and diversity of suppliers in the Southern States could potentially result in gas users in the Southern States paying at least $2/GJ less for their gas.

4.3.3. Prices agreed for 2018 under long term contracts

This section sets out the ACCC's findings on the wholesale price of gas that producers and retailers are expected to receive in 2018 under GSAs entered into between January 2016 and May 2017 with gas buyers in Queensland and the Southern States. This time period has been employed to ensure that prices under legacy contracts are not included and that only prices are included that have been agreed since all three east coast LNG projects have been exporting.

The gas prices cited in this section have been estimated using the pricing mechanisms specified in each GSA and the assumptions relating to key variables such as oil prices, foreign exchange rates and CPI. In a similar manner to the analysis set out in section 4.2, the prices that producers are expected to receive have been calculated using the GSAs entered into with all buyers, while the prices retailers are expected to receive are based on the GSAs that have been entered into with C&I users.

The ACCC notes that the contract prices and averages cited in this section are not adjusted to reflect any differences in non-price terms specified in the contracts, such as take-or-pay

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152 EnergyQuest, *EnergyQuarterly*, September 2017, p. 63.

153 Based on conversions of: A$1 = US$0.79, 1 MMBtu = 1.055 GJ.

154 Shipping costs and losses are averages based on information provided to the ACCC by the east coast LNG projects.

155 Marginal liquefaction costs are averages based on information provided to the ACCC by the east coast LNG projects.

156 Indicative gas prices are ex-plant at Longford.

157 Seller transport costs are estimated at AU$2.92 based on average pipeline tariffs reported in the ACCC's previous inquiry and escalated by CPI.

158 Buyer transport costs are estimated at AU$2.22 based on average pipeline tariffs report in the ACCC's previous inquiry and escalated by CPI.

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.

Queensland

In 2018, all of Queensland's domestic demand is expected to be met by Queensland production, and it is expected that around 85 per cent of C&I demand will be supplied by the LNG projects.

As discussed above, in a well-functioning market, it would be expected that Queensland gas prices in 2018 would be shaped by the LNG spot netback.

Table 4.2 shows volume weighted average gas price estimates for 2018 based on Queensland contracts entered into since the beginning of 2016. It also shows the ACCC's estimate of the LNG spot netback (discussed above) and the contract netback, which is calculated using estimated 2018 LNG contract prices, averaged across the three LNG projects.

It should be noted that out of the four producer contracts agreed, two are oil-linked. This means that, 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, which may not reflect actual movements and current expectations about these variables for 2018.

Table 4.2: Volume weighted average gas prices and netback prices in Queensland, 2018 est.[159]

Type of supplier	Volume weighted average gas price ($/GJ)	LNG netback to Wallumbilla ($/GJ)
Producer	7.33	5.87 (spot) 8.00 (contract)
Retailer	8.74	

Source: ACCC analysis of contracts provided by suppliers

Note: Averages are based on four producer and three retailer contracts.

The ACCC emphasises that these averages are based on a small number of contracts. Only four producer and three retailer contracts were entered into in Queensland between January

159 In all estimates of 2018 prices, the following assumptions are made, where relevant:

- 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 31 August 2017) is 79 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 29 August 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$51.73/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.

2016 and May 2017, with each of the producer contracts including an LNG project as a supplier and a C&I user as a buyer.

There were 13 unfulfilled offers from the LNG projects over the period from January 2016 to July 2017 – mostly to counterparties other than those who entered into contracts – with 2018 price offers of around $7.40-8.30/GJ (unfulfilled offers are discussed further in section 4.3.4

Producer prices agreed under new GSAs ranged $7.20-$7.70/GJ, while the retailer prices ranged from around $8.60 to just below $9.00/GJ.

The producer prices are all in excess of the estimated LNG spot netback of $5.87/GJ and below the LNG contract netback of $8.00/GJ.

The ACCC has not fully explored the reasons for differences between commodity gas charges between producers and retailers for the purposes of this report, but intends to do so during the course of the Inquiry. It is worth noting though that none of the executed retailer contracts are oil-linked. Some of the differential may therefore reflect hedging costs. The difference may also reflect other wholesale gas-related costs incurred by retailers, such as the cost of storing gas for peak supply periods.

All of the prices noted above were struck in late 2016 and early 2017, when the level of price offers was at its peak. The average price offer from the LNG projects to Queensland buyers around this time was about $8/GJ, so while some C&I users were able to achieve lower prices, they are still higher than LNG spot netback.

Thus, to the extent that the LNG projects expect to have excess gas beyond what is required to meet their minimum export contract obligations in 2018 that could be sold onto the international LNG spot markets, at this level of domestic prices, it is likely be more commercially attractive to sell gas domestically.

Almost all unfulfilled offers for 2018 supply made in Queensland since the start of 2016 were from the LNG projects, and the only contracts entered into were with the LNG projects at prices above LNG spot netback. This suggests there may be a lack of competition between these suppliers in Queensland. Indeed, it appears that almost all domestic unfulfilled offers for 2018 supply by LNG projects were made by QGC.

Southern States

Unlike Queensland, only a small proportion of gas produced in the Southern States is sold directly to C&I users. Retailer supply to these users is more prevalent.

As discussed in chapter 2, it is expected that there will be a supply shortfall in the Southern States in 2018. Gas from the northern supply sources (either from Queensland or the Cooper Basin) will therefore be needed to mitigate the expected southern shortfall. As discussed above, in these circumstances, an appropriate benchmark price for comparing prices charged by producers in the Southern States would be the delivered prices of Queensland gas in the Southern States (being $7.54/GJ in Adelaide, $7.87/GJ in Sydney and $8.14/GJ in Melbourne) less an amount to account for transportation depending on the user's location ($0.37-1.25/GJ). This gives a range of benchmark prices that producers in Victoria would expect to receive at the wellhead of between $6.29-7.77/GJ, depending on the user's location.

Table 4.3 shows volume weighted average gas price estimates for 2018 based on contracts that have been entered into in the Southern States since the beginning of 2016.

As is the case in some Queensland contracts, all of the Victorian producer contracts executed between January 2016 and May 2017 are oil-linked. This means that, 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, which may not reflect actual movements and current expectations about these variables for 2018.

Table 4.3: Volume weighted average commodity gas prices in the Southern States, 2018 est.

Type of seller	Volume weighted average commodity gas price ($/GJ)
Producer (VIC only)	7.29
Retailer (VIC)	8.78
Retailer (NSW)	7.79
Retailer (SA)	6.62

Source: ACCC analysis of contracts provided by suppliers

Note: Averages are based on three producer and three retailer contracts for each of VIC and SA, and five retailer contracts in NSW. Commodity gas prices do not include the cost of transportation and other ancillary charges.

The ACCC emphasises that, as for Queensland, average prices for each location are based on a small number of contracts. Only three producer contracts were entered into in Southern States between January 2016 and May 2017.

Only three retailer contracts in each of Victoria and South Australia, and five in NSW, were entered into over the same period. This gives a total of 14 contracts entered into for 2018 supply since January 2016.

The ACCC's analysis of unfulfilled offers between January 2016 and July 2017 indicates that over 50 offers made in the Southern States were not accepted by potential buyers (across all types of buyer, but excluding multiple offers to the same buyer). Some of these offers were made to counterparties which ultimately contracted for supply in 2018, but the majority appear to remain unfulfilled.[160]

There is a greater degree of variation between 2018 prices agreed in the Southern States relative to those in Queensland. Producer prices in Victoria range from $5.90-8.40/GJ, while retailer prices in that state range from $7.90-9.80/GJ. In South Australia and NSW, retailer prices range from $6.00-9.90/GJ. It is again noted, however, that prices charged by retailers for commodity gas may include retail margins and other types of costs, so they are not directly comparable with wholesale producer gas prices. In addition, as noted above, given that none of the executed retailer contracts are oil-linked, some of the differential may reflect hedging costs.

[160] It is noted, however, that not all of the offers that were made over this period could have been fulfilled (that is, if some offers were accepted, that gas would not have been available for other offers).

Some of the prices struck for 2018 supply between producers and gas users in Victoria are lower than the benchmark price for Victoria, however these prices were agreed earlier in the period analysed. The most recent price agreed with a Victorian producer (around $8.40/GJ) is above the upper end of the benchmark price range.

4.3.4. Unfulfilled offers for gas supply in 2018

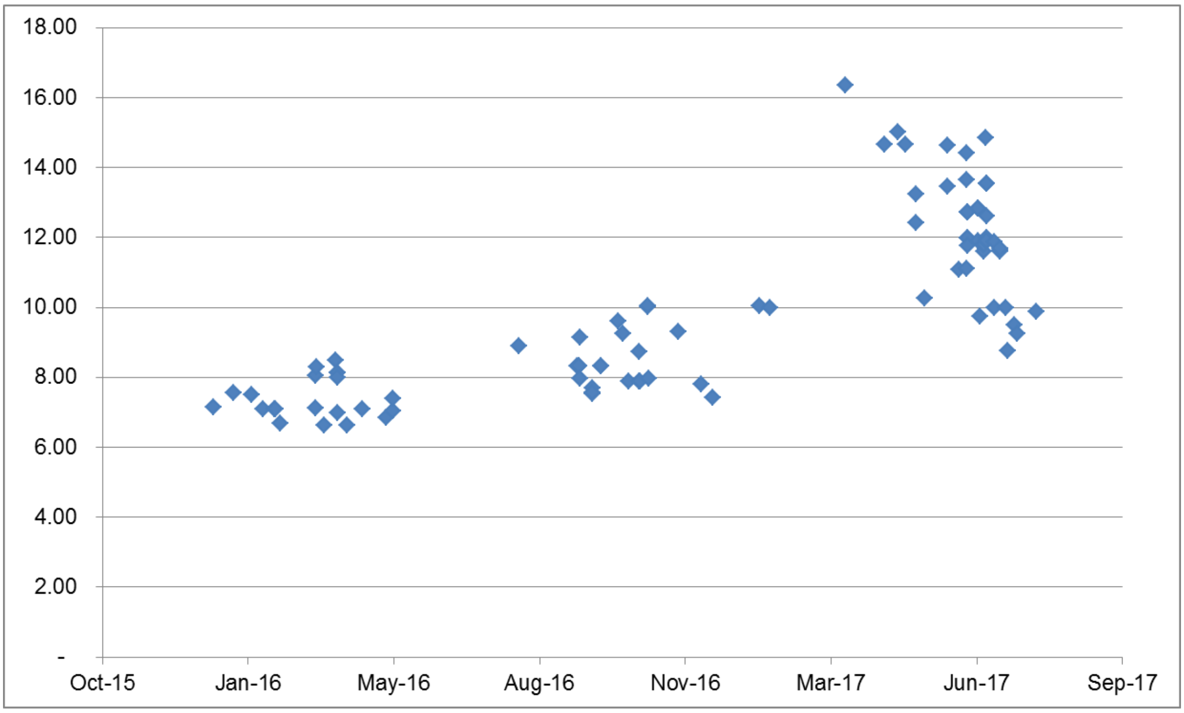
Prices agreed for 2018 supply do not provide a full picture of the market. As noted above, few contracts have been entered into for 2018 supply since January 2016. Further, as discussed in chapter 3, a number of C&I users are deferring agreeing to contracts for 2018 supply and beyond due to the high price of offers.

To provide a more complete view of the market over this period, the ACCC has obtained information from gas suppliers on 'unfulfilled offers' in the East Coast Gas Market. These are written offers for gas supply in 2018 of at least 1 PJ per annum that did not result in a contract by 14 July 2017.

Chart 4.5 below shows the prices included in unfulfilled offers that were made by suppliers for 2018 gas supply over the period from January 2016 to July 2017. These include offers from both producers and retailers, to buyers including retailers, C&I users and GPGs. Consistent with the gas prices presented elsewhere in this chapter, these prices reflect offers made for commodity gas only – that is, not including the cost of transporting gas to the users' end location. It should be noted that, as in the case of contract prices, unfulfilled offers from retailers may capture retailer margins and other types of costs.

It should also be noted that not all of the price offers in the chart are for unique combinations of seller and buyer. That is, some offers in the chart reflect follow up offers that were made by the same supplier to the same customer after a previous offer did not result in a contract. Further, the price offers are not all directly comparable, as they may differ on non-price terms such as contract quantities, take or pay levels, or contract duration. The chart is intended to give an indication of how the level of price offers has evolved since the start of 2016.

Chart 4.5: Unfulfilled offers across East Coast Gas Market made between January 2016 and July 2017 ($2018/GJ for commodity gas)



Source: ACCC analysis of unfulfilled offers provided by suppliers

As shown in the chart, there have been three distinct periods where unfulfilled offers were made – early 2016, late 2016 and early-to-mid 2017. The latter two periods show clear increases in the level of prices being offered for 2018 supply.

Across all unfulfilled offers over the period, there is a clear relationship between price offered and the proposed contract quantity. The volume weighted average price for unfulfilled offers below the median annual contract quantity is $10.75/GJ, while the volume weighted average price for unfulfilled offers above the median quantity is $8.94/GJ. It should be noted, however, that all of these unfulfilled offers are for volumes of at least 1 PJ per annum. Some C&I users seeking supply for volumes below this level – who are typically supplied by retailers – have reported price offers at the upper end of, and in some cases above, the range shown in the chart above.[161]

There is also a distinct relationship between price and contract duration, with the volume weighted average of unfulfilled offers for one year or less being $10.15/GJ and the average of unfulfilled offers for two or more years being $8.68/GJ.

The lowest unfulfilled offer was made in early 2016 to a C&I user, with a price of $6.64/GJ. The highest unfulfilled offer was made in early 2017 to a C&I user, with a price of $16.36/GJ. The unfulfilled offers made over the first few months of 2017 (which were mostly to buyers in the Southern States) were all over $10/GJ. It is noted again that the unfulfilled offers in chart 4.5 are from both producers and retailers.

Recognising the caveat noted above in relation to retailer commodity gas charges and the potential for them to reflect other types of retailer-specific costs, these price levels are significantly above what the ACCC considers to be the range of appropriate benchmark prices in the Southern States.

[161] For example see: 'Bid for gas export cap to curb prices', *The Age*, 7 June 2017.

The ACCC notes, however, that following a peak of unfulfilled price offers in early 2017, there has been a steady decline in the level of price offers made over the course of the year. Most recent unfulfilled offers have been made at or below $10/GJ, but still above benchmark prices. There have been recent public comments by producers that prices have fallen in the first half of the year.[162] While this might indicate some increased participation or competition in supplying customers, the ACCC notes that this coincides with the ACCC seeking information from suppliers as part of this Inquiry, as well as the government's steps to implement policy measures to address concerns with the gas market.

162 'Shell chief expects gas export clampdown', *The Australian*, 7 September 2017.

Appendix 1

TREASURER

Mr Rod Sims
Chairman
Australian Competition and Consumer Commission
GPO Box 3131
CANBERRA ACT 2601

Dear ~~Mr Sims~~ Rod

I am writing to require the Australian Competition and Consumer Commission (ACCC) to hold an inquiry to improve transparency and to monitor gas supply in Australia pursuant to subsection 95H(1) of the *Competition and Consumer Act 2010* (CCA).

I enclose a notice under subsection 95H(1) of the CCA identifying the matters the inquiry is to consider and when the inquiry is to be completed.

This inquiry will improve transparency of the gas market in Australia and support the efficient operation of the gas market. It will also monitor the gas supply market and help to identify if gas suppliers are net contributors to the domestic gas market and are delivering on the gas supply guarantee announced by the Prime Minister on 15 March 2017.

The final report must be submitted by 30 April 2020, with interim reporting at least every six months. The ACCC will also provide information to the market as appropriate. I understand the ACCC will require additional resources to undertake this inquiry.

I have copied this letter to the Prime Minister and the Minister for the Environment and Energy.

Yours sincerely

The Hon Scott Morrison MP
19 / 4 / 2017

COMMONWEALTH OF AUSTRALIA

COMPETITION AND CONSUMER ACT 2010

INQUIRY FOR IMPROVING THE TRANSPARENCY OF GAS SUPPLY IN AUSTRALIA

I, Scott Morrison, Treasurer, pursuant to subsection 95H(1) of the Competition and Consumer Act 2010, hereby require the Australian Competition and Consumer Commission (ACCC) to hold an inquiry into:

- measures to improve the transparency of gas supply arrangements in Australia;
- the supply by persons in the gas industry (including without limitation gas producers and gas retailers) of, and demand for, natural gas extracted or produced in Australia, or imported into Australia; and
- the supply of, and demand for, natural gas transportation services in Australia by persons in the gas industry (including without limitation gas pipeline operators and other persons who have access to pipeline capacity).

Matters to be monitored and taken into consideration in the inquiry shall include, but not be restricted to:

- the pricing and availability of offers to supply gas;
- the volumes of gas supplied or available for current or future supply, including natural gas extracted or produced in Australia, or imported into Australia;
- the pricing, volume and availability of gas for domestic supply compared to the pricing, volume and availability of gas for export;
- the pricing, volume and availability of other goods or services, such as goods or services for drilling for, storing or processing gas, that enable, assist or facilitate the supply of gas or gas transportation services in Australia.

The ACCC should make use of publicly available information on the gas industry, including that published by the Australian Energy Market Commission, the Australian Energy Market Operator or the Australian Energy Regulator, where appropriate. This is not to be an inquiry into supply by any particular person or persons, or by a State or Territory Authority.

The inquiry is to commence today. The inquiry is to submit interim reports to me no less frequently than every 6 months and provide information to the market as appropriate. The inquiry is to be completed and a final report submitted to me by 30 April 2020.

DATED THIS 19th DAY OF April 2017

SCOTT MORRISON
Treasurer