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<th>Description</th>
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<tr>
<td><strong>ABS</strong></td>
<td>Australian Bureau of Statistics</td>
</tr>
<tr>
<td><strong>ACCC</strong></td>
<td>Australian Competition and Consumer Commission</td>
</tr>
<tr>
<td><strong>ACCC's 2015 Inquiry</strong></td>
<td>The ACCC's inquiry into the East Coast Gas Market in 2015, as reported on in April 2016.</td>
</tr>
<tr>
<td><strong>ACQ</strong></td>
<td>Annual contract quantity</td>
</tr>
<tr>
<td><strong>AEMC</strong></td>
<td>Australian Energy Market Commission</td>
</tr>
<tr>
<td><strong>AEMO</strong></td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td><strong>AEMO-operated wholesale markets</strong></td>
<td>There are two broad kinds of AEMO-operated wholesale markets: demand hubs, and supply hubs. The Victorian Declared Wholesale Gas Market (DWGM) and the Adelaide, Sydney, and Brisbane Short-Term Trading Markets (STTMs) can be considered demand hubs as their primary purpose is to meet the gas requirements of a particular demand centre. These markets are compulsory—if a user sits within the defined boundaries of the market, their gas use (or supply) will be scheduled through the market by AEMO. The Wallumbilla and Moomba Gas Supply Hubs were developed primarily to facilitate the trade of gas between suppliers and large users at a particular supply centre. These markets are voluntary.</td>
</tr>
<tr>
<td><strong>AER</strong></td>
<td>Australian Energy Regulator</td>
</tr>
<tr>
<td><strong>AGP</strong></td>
<td>Amadeus Gas Pipeline</td>
</tr>
<tr>
<td><strong>AIE</strong></td>
<td>Australian Industrial Energy</td>
</tr>
<tr>
<td><strong>Annual contract quantity</strong></td>
<td>The quantity of gas specified in the transportation contract between the buyer and the seller, based on the buyer’s maximum historical 12-month usage.</td>
</tr>
<tr>
<td><strong>APLNG</strong></td>
<td>Asia Pacific LNG</td>
</tr>
<tr>
<td><strong>APPEA</strong></td>
<td>Australian Petroleum Production and Exploration Association</td>
</tr>
<tr>
<td><strong>ASX</strong></td>
<td>Australian Securities Exchange</td>
</tr>
<tr>
<td><strong>Buyer alternative</strong></td>
<td>the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user’s location. It represents a price ceiling in negotiations.</td>
</tr>
<tr>
<td><strong>C&amp;I</strong></td>
<td>commercial and industrial</td>
</tr>
<tr>
<td><strong>Capacity trading platform</strong></td>
<td>An online platform that shippers can use to trade secondary capacity ahead of the nomination cut-off time. It provides for exchange-based trading of commonly traded products and a listing service for more-bespoke products. The CTP forms part of the Gas</td>
</tr>
</tbody>
</table>
### Supply Hub exchange.

<table>
<thead>
<tr>
<th>CGP</th>
<th>Carpentaria Gas Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>COAG</td>
<td>Council of Australian Governments (cessation in May 2020)</td>
</tr>
<tr>
<td>Congestion</td>
<td>A pipeline is congested when there is insufficient spare capacity to transport the volume of gas to fulfil demand. Physical congestion refers to where demand for actual deliveries exceeds the technical capacity of the pipeline at some point in time, whereas a pipeline is contractually congested when the demand for firm capacity exceeds the technical capacity of the pipeline.</td>
</tr>
<tr>
<td>Conventional gas</td>
<td>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.</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
<tr>
<td>CSG</td>
<td>coal seam gas</td>
</tr>
<tr>
<td>CTP</td>
<td>capacity trading platform</td>
</tr>
<tr>
<td>DAA</td>
<td>day-ahead auction</td>
</tr>
<tr>
<td>Day-ahead auction</td>
<td>An auction of contracted but un-nominated capacity. It is conducted after nomination cut-off and is subject to a reserve price of zero. Compressor fuel is provided in-kind by shippers.</td>
</tr>
<tr>
<td>Domestic demand</td>
<td>The quantity of gas demanded by users located in Australia.</td>
</tr>
<tr>
<td>Downward quantity tolerance</td>
<td>The amount a buyer may fall short of its full Annual Contract Quantity in a Take or Pay gas sales contract without incurring penalties.</td>
</tr>
<tr>
<td>DQT</td>
<td>downward quantity tolerance</td>
</tr>
<tr>
<td>DWGM</td>
<td>Declared Wholesale Gas Market</td>
</tr>
<tr>
<td>East coast gas market</td>
<td>The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.</td>
</tr>
<tr>
<td>EBITDA</td>
<td>Earnings before interest, tax, depreciation and amortisation</td>
</tr>
<tr>
<td>EGP</td>
<td>Eastern Gas Pipeline</td>
</tr>
<tr>
<td>Acronym</td>
<td>Full Form</td>
</tr>
<tr>
<td>---------</td>
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</tr>
<tr>
<td>EMM</td>
<td>Energy Ministers’ Meeting</td>
</tr>
<tr>
<td>ENCRC</td>
<td>Energy National Cabinet Reform Committee</td>
</tr>
<tr>
<td>Export demand</td>
<td>The quantity of Australian gas demanded by overseas buyers.</td>
</tr>
<tr>
<td>FID</td>
<td>financial investment decision</td>
</tr>
<tr>
<td>FSRU</td>
<td>floating storage and regasification unit</td>
</tr>
<tr>
<td>Gas supply agreement</td>
<td>A contract between the buyer and seller for the supply of gas</td>
</tr>
<tr>
<td>Gas transportation agreement</td>
<td>A contract between the shipper and the pipeline operator for the transport of gas on that pipeline</td>
</tr>
<tr>
<td>GBJV</td>
<td>Gippsland Basin Joint Venture</td>
</tr>
<tr>
<td>GLNG</td>
<td>Gladstone LNG</td>
</tr>
<tr>
<td>GMRG</td>
<td>Gas Market Reform Group</td>
</tr>
<tr>
<td>GPG</td>
<td>gas powered generation/generator</td>
</tr>
<tr>
<td>GSA</td>
<td>gas supply agreement</td>
</tr>
<tr>
<td>GSOO</td>
<td>Gas Statement of Opportunities</td>
</tr>
<tr>
<td>GSSA</td>
<td>Gas Storage Service Agreement</td>
</tr>
<tr>
<td>GTA</td>
<td>gas transportation agreement</td>
</tr>
<tr>
<td>Heads of Agreement</td>
<td>In the context of this report, this refers to an agreement between LNG producers and the Australian Government to offer uncontracted gas first to the domestic market on ‘competitive market terms’ before it is offered to the international market.</td>
</tr>
<tr>
<td>Henry Hub</td>
<td>Is the major gas hub for spot and futures trading in the United States and acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of nine interstate and four intrastate pipelines in Louisiana.</td>
</tr>
<tr>
<td>ICE</td>
<td>Intercontinental Exchange</td>
</tr>
<tr>
<td>Japan Customs Cleared</td>
<td>Represents the average price of crude oil imported to Japan and reported by the Japanese Custom. It is commonly used as an index by LNG traders.</td>
</tr>
<tr>
<td>Japan Korea Marker</td>
<td>Is an international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.</td>
</tr>
<tr>
<td>JCC</td>
<td>Japanese Customs Cleared</td>
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<tr>
<td><strong>JKM</strong></td>
<td><strong>Japan Korea Marker</strong></td>
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<tr>
<td><strong>Liquefaction</strong></td>
<td><strong>The process of liquefying natural gas.</strong></td>
</tr>
<tr>
<td><strong>Liquefied natural gas (LNG)</strong></td>
<td><strong>Natural gas that has been converted to liquid form for ease of storage or transport.</strong></td>
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<tr>
<td><strong>LNG</strong></td>
<td><strong>liquefied natural gas</strong></td>
</tr>
<tr>
<td><strong>LNG netback price</strong></td>
<td><strong>A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or ‘netting back’ costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.</strong></td>
</tr>
<tr>
<td><strong>LNG producer</strong></td>
<td><strong>LNG producers process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this report, the term is usually used in reference to one or more of the three LNG producers in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG producers in the Northern Territory and in Western Australia.</strong></td>
</tr>
<tr>
<td><strong>LNG train</strong></td>
<td><strong>A liquefied natural gas plant’s liquefaction and purification facility.</strong></td>
</tr>
<tr>
<td><strong>Load factor</strong></td>
<td><strong>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.</strong></td>
</tr>
<tr>
<td><strong>Looping</strong></td>
<td><strong>Increasing the capacity of a pipeline system, by adding parallel piping along parts or the whole of the route. This does not include adding compression facilities.</strong></td>
</tr>
<tr>
<td><strong>MAPS</strong></td>
<td><strong>Moomba to Adelaide Pipeline System</strong></td>
</tr>
<tr>
<td><strong>MDQ</strong></td>
<td><strong>maximum daily quantity</strong></td>
</tr>
<tr>
<td><strong>MOU</strong></td>
<td><strong>Memorandum of Understanding</strong></td>
</tr>
<tr>
<td><strong>MSP</strong></td>
<td><strong>Moomba to Sydney Pipeline</strong></td>
</tr>
<tr>
<td><strong>NEM</strong></td>
<td><strong>National Electricity Market</strong></td>
</tr>
<tr>
<td><strong>NGL</strong></td>
<td><strong>National Gas Law</strong></td>
</tr>
<tr>
<td><strong>NGP</strong></td>
<td><strong>Northern Gas Pipeline</strong></td>
</tr>
<tr>
<td><strong>NGR</strong></td>
<td><strong>National Gas Rules</strong></td>
</tr>
<tr>
<td><strong>PCA</strong></td>
<td><strong>Port Campbell to Adelaide Pipeline</strong></td>
</tr>
</tbody>
</table>
## Pipeline transportation services

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

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

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

**Compression service:** A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

### Producer

Gas producers extract gas and process it for transmission and sale.

### QGC

**QGC LNG**

### QGP

Queensland Gas Pipeline

### RBA

Reserve Bank of Australia

### RBP

Roma to Brisbane Pipeline

### Reserves and resources

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

**Developed reserves:** Gas expected to be recovered from existing wells and facilities

**Undeveloped reserves:** Gas that requires further investments to bring online.

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

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

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

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

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

<p>| Retailer | For the purpose of this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy and Shell Energy Australia. |
| RIS | Regulation Impact Statement |
| Sale and purchase agreement | An agreement between the buyer and seller for LNG. In this report |
| Seller alternative | The LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher). It represents a price floor in negotiations |
| Southern states | South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania. |
| SPAs | sale and purchase agreements |
| Spot market transaction | The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for delivery on a single gas day shortly after the transaction has been finalised. Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts. |
| Standing prices | Prices or reference tariffs that pipelines subject to Part 23 of the National Gas Rules, light regulation or full regulation are required to publish. |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
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<tbody>
<tr>
<td>STTM</td>
<td>Short-term trading market</td>
</tr>
<tr>
<td>Swap arrangement</td>
<td>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.</td>
</tr>
<tr>
<td>SWQP</td>
<td>South West Queensland Pipeline</td>
</tr>
<tr>
<td>Take or pay</td>
<td>A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year. Take-or-pay multipliers are expressed as a percentage in GSAs, and provide users with flexibility in how they manage their gas usage.</td>
</tr>
<tr>
<td>Tenement</td>
<td>A claim, lease or licence for the purpose of prospecting or mining gas.</td>
</tr>
<tr>
<td>TGP</td>
<td>Tasmanian Gas Pipeline</td>
</tr>
<tr>
<td>Transportation and</td>
<td><strong>Contracted but un-nominated capacity</strong>: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.</td>
</tr>
<tr>
<td>storage related terms:</td>
<td><strong>Gas storage service</strong>: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).</td>
</tr>
<tr>
<td></td>
<td><strong>Secondary capacity</strong>: Capacity that is on-sold by primary capacity holders on a pipeline.</td>
</tr>
<tr>
<td></td>
<td><strong>Shipper</strong>: A user or prospective user of pipeline services.</td>
</tr>
<tr>
<td>Unconventional gas</td>
<td>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:</td>
</tr>
<tr>
<td></td>
<td><strong>shale gas</strong>: natural gas contained within shale rock</td>
</tr>
<tr>
<td></td>
<td><strong>coal seam gas (CSG)</strong>: natural gas contained in coalbeds</td>
</tr>
<tr>
<td></td>
<td><strong>tight gas</strong>: natural gas found in low permeability rock formations.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Units</td>
<td><strong>bbl</strong>: barrel of oil</td>
</tr>
<tr>
<td></td>
<td><strong>MMBtu</strong>: Million British Thermal Units—see below, Units of Energy</td>
</tr>
<tr>
<td></td>
<td><strong>Mtpa</strong>: million tonnes per annum</td>
</tr>
</tbody>
</table>
**GJ**: Gigajoule  
**PJ**: Petajoule  
**TJ**: Terajoule

| Units of Energy   | Joule—a unit of energy in the International System of Units  
|                  | Gigajoule (GJ)—a billion joules  
|                  | Terajoule (TJ)—a trillion joules  
|                  | Petajoule (PJ)—a quadrillion joules  
|                  | Million British Thermal Units (MMBtu)—a unit of heat; 1 MMBtu = approximately 1.055 GJ |

**VTS**: Victorian Transmission System  
**WAP**: weighted average price
Gas inquiry interim report findings
January 2022

Gas Prices
Prices offered for supply in 2022 increased from $6-8/GJ in late 2020 to $7-9.50/GJ by mid 2021.

LNG netback prices
International LNG prices increased by ~230% between February and August 2021.

2022 supply outlook
Supply should be sufficient to meet demand, however southern states will be reliant on gas from Queensland.

Long-term supply
Forecast production will be insufficient to meet forecast demand in the East Coast Gas Market from 2026.

Reserves & resources
Since July 2020 there has been a further net writedown of reserves and resources.

Supply & infrastructure
Additional supply from an LNG import terminal or new domestic sources is required to avoid a shortfall before 2026.

Transport & storage prices
Prices have generally increased in line with inflation, emphasising the importance of upcoming regulatory reforms.

User experience
Users have reported deteriorating market conditions.

Upstream competition review
Structural factors are impeding competition in the upstream market. We recommend reforms to encourage diversity of suppliers and reduce barriers faced by producers.
Overview

This is the January 2022 interim report of the Australian Competition and Consumer Commission’s (ACCC’s) inquiry into gas supply in Australia (the Inquiry).

In our July 2021 interim report we observed that domestic gas prices across the east coast, as well as international LNG prices, had trended downwards over 2020 and that prices for 2022 had stabilised at the beginning of 2021. Our latest analysis shows that domestic prices have risen, with prices offered for 2022 supply increasing from $6-8/GJ in late 2020 to around $7-$9.50 by mid-2021.

Despite the rise in domestic prices, they did not increase as significantly as international LNG prices, which increased by almost 230% in the Asian LNG spot market between late February and late August 2021. As a result, many domestic offers have been below export parity prices more recently. There are likely to be several factors contributing to this deviation between domestic and international LNG prices. These include expectations of relatively stable oil-linked LNG netback prices amid volatility in Japan Korea Marker (JKM) futures markets, short-term domestic market dynamics and concerns over regulatory intervention in the domestic east coast gas market. Asian LNG spot prices have risen further since August and by 6 January 2022 were trading at the equivalent of around $44/GJ.

In our July 2021 interim report some Commercial and Industrial (C&I) users reported improved market conditions, including more offers from a range of suppliers and a willingness to negotiate some flexibility in contract terms. However, users expressed strong concern that these improvements would not last. Our most recent examination of users’ experiences suggests these concerns were valid. Users have reported that they are receiving limited offers from suppliers, with those making offers proposing higher prices and being less willing to negotiate flexible terms, particularly for supply from 2023. In November 2021, Incitec Pivot Limited announced it will cease manufacturing at its Brisbane-based Gibson Island plant at the end of 2022, as it had been unable to secure affordable gas supply from 2023 onwards. A voluntary code of conduct for the negotiation of contracts between gas suppliers and users was announced on 1 December 2021 and is due to commence on 1 June 2022. The more gas producers and retailers that sign up to the code, the greater the benefits for users. We will monitor the operation of the code as part of our inquiry.1

The deteriorating market conditions reported by users is consistent with what we are observing with the supply outlook for 2022 and beyond. While supply from proved and probable (2P) reserves should be sufficient to meet demand across the east coast in 2022, a shortfall of 10 PJ is forecast for the southern states. This shortfall could be alleviated by supply from the north, which is forecast to have a 19 PJ surplus. The southern states are therefore expected to be more reliant on gas flowing south from 2022 to avoid a shortfall.

The long-term supply outlook is less positive. The shortfall in the southern states is forecast to continue in 2023 and beyond, which is two years earlier than we previously forecast. Additional supply from an LNG import terminal in the south, or more domestic supply from the north will be required to address this shortfall. It may also be necessary to divert some gas into the domestic market that would otherwise be exported if new supply cannot be developed rapidly enough.

1 The ACCC has no formal role under the voluntary code and a regular review process will be completed by an independent reviewer. See: Angus Taylor, ‘Gas industry finalises voluntary code of conduct’ (Media statement), 1 December 2021; Australian Petroleum Production and Exploration Association, ‘Code of Conduct finalised’ (Media statement), 1 December 2021; Australian Industry Group, ‘New code is one piece of a large gas policy puzzle’ (Media statement), 1 December 2021.
Capacity is fully contracted, or close to fully contracted, in the near term on pipelines and compression facilities that are used to transport gas south from Queensland. APA has, however, commenced work on expanding the capacity of the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP) to enable more gas to flow from the north. Construction has also begun on the LNG import terminal at Port Kembla, but there is still uncertainty surrounding this project. Both projects are proposed to be completed in 2023, which could help alleviate the forecast southern shortfall.

In the east coast more generally, a shortfall in supply from 2P reserves is expected to emerge from 2026. This has been driven, in part, by further write-down of 2P reserves, with reserves written down by around 1,117 PJ in the 12 months to 30 June 2021. This is the fourth year we have reported significant write downs, with 2P reserves having been written down by around 8,955 PJ (~21%) since 2017, the majority of which have been written down by LNG producers in Queensland.

While there are a number of new domestic sources of supply and LNG import projects that could potentially be brought online to address the projected shortfall, they are more speculative in nature and have not yet been sanctioned. Before they can be sanctioned, these projects will need to overcome a range of barriers, and significant investment in infrastructure will be required to bring the gas to market.

Stage 1 of our review of upstream competition and the timeliness of supply has found that there are a number of structural factors impeding upstream competition and limiting gas supply. We recommend that state, territory and Commonwealth governments implement a range of reforms to:

- encourage greater diversity of suppliers through the processes used to release acreage and play a more proactive role in encouraging gas to be developed in a timely manner
- reduce the infrastructure, capital and regulatory related barriers that producers can face, including by introducing a third party access regime for upstream infrastructure (this includes gathering pipelines, natural gas processing, water treatment and compression facilities) and storage facilities.

The uncertainty surrounding the supply outlook in 2022 and beyond emphasises the importance of the Australian Government’s Heads of Agreement (HoA) with LNG producers which concludes on 1 January 2023. While LNG producers expect to have 122 PJ of uncontracted gas they could supply into the market for 2022, they are expecting to withdraw 27 PJ more from the east coast gas market than they expect to supply into it. They are also intending to supply around half the amount of gas they supplied into the domestic market each year in 2017 and 2018.

In our July 2021 report we concluded that some of the LNG producers had not clearly demonstrated compliance with the HoA. We also made it clear that we expected the LNG producers to significantly improve the evidence they provide to substantiate compliance. While the quality of what LNG producers have reported has improved, we continue to have concerns about how some have approached demonstrating compliance with the HoA. Specifically, that some gas originally offered in some EOI processes was not ultimately able to be supplied to domestic customers and whether reasonable notice was provided. Further, many domestic offers from LNG producers for long term supply do not appear to have been internationally competitive as required by the HoA, and some LNG producers have provided

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2 Under the HoA, LNG producers have committed to not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market (see section 4.6).
insufficient information regarding their consideration of LNG prices when making domestic offers.

Transportation costs will start to have a more significant effect on prices in the south if more gas is to flow from the north into the southern states. It will therefore be important for transportation costs to reflect the efficient cost of transporting the gas. The majority of transportation charges are rising in line with inflation. Unfortunately, this suggests that the monopoly pricing we first observed in 2016 continues.

Upcoming changes to the gas pipeline regulatory framework are expected to pose more of a constraint on monopoly pricing and other exercises of market power by pipeline operators. A key element of the reforms is the requirement for pipeline operators to publish the individual prices paid for services, which is designed to provide greater transparency. South Australia is considering derogating from this requirement, which would compromise the effectiveness of the reforms in that state.

Effective monitoring and enforcement of the reforms by the AER will also be critical in ensuring they have the intended effect. In June 2021, the AER announced that one of its key enforcement and compliance priorities for 2021-22 was to ‘(e)nsure service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations’.

**Prices have increased moderately compared to the steep rise in expected LNG netback prices**

Prices offered for 2022 supply in the domestic market increased over the first half of 2021, although not in line with expected LNG spot prices or oil indices. The ACCC’s work in recent years has found that both Asian LNG spot and oil prices influence prices offered in the east coast gas market. For this reason, the ACCC currently uses the Japan Korea Marker (JKM), a measure of Asian LNG spot prices, to calculate LNG netback prices extending to two years into the future. As we have previously reported, oil futures are often used by suppliers as a domestic reference price, particularly for supply periods beyond where short-term LNG futures markets are considered liquid. This was confirmed recently as part of our LNG netback review.
Chart 1: Historical and future Brent Crude oil and JKM prices

Source: ICE, S&P Global Platts, EIA, ACCC analysis.

Historical and expected futures prices for both Brent Crude oil and JKM are set out in chart 1. At the onset of the COVID-19 pandemic, Brent Crude prices fell to a USD18.38 per barrel low in April 2020. Brent Crude prices have increased rapidly since then, peaking at USD83.54 per barrel in October 2021. As at 12 November 2021, market expectations suggest Brent Crude prices will decline gradually in 2022, with the December 2022 futures price assessed at USD74.81 per barrel.

JKM prices spiked to an all-time high in November 2021, following a sustained increase in European gas prices and a global energy shortage. Expected 2022 JKM prices increased steeply during the first half of 2021 due to forecasts of a global supply crunch in LNG markets during the Asian 2021-22 winter. As at 12 November 2021, JKM prices are expected to decline significantly during Q2 2022, with the April 2022 futures prices assessed at USD18.10 per MMBtu.

Prices offered for supply in 2022 in the domestic east coast market increased moderately in mid-2021 and did not reflect the significant increases in expected LNG netback prices. Expected 2022 LNG netback prices overtook prices offered for 2022 supply in Queensland and the southern states in March and April 2021, respectively.

Prices offered for 2022 supply by gas producers increased from a range of $6.50-8.20/GJ in late 2020 to $6.70–9.40/GJ in mid-2021. Over this period, prices offered by retailers also increased from $6.00–9.00/GJ to $7.20–9.60/GJ.

Offers to the southern states for 2022 supply became more dispersed over 2021, clustering around $8/GJ in March and widening to a range between $7.20/GJ and $9.60/GJ towards the middle of the year. Chart 2 compares offers by producers and retailers in the southern states for 2022 supply made between 1 January 2020 and 16 August 2021.
This chart shows that the number of offers and bids for 2022 supply increased between March and August 2021 following a significant reduction in offers, particularly by retailers, in late 2020 and early 2021 summer. There were approximately 175% more offers reported between March and August 2021 than between September 2020 and February 2021. Market activity during this period also exceeded January–August 2020 levels.

In our July 2021 report we observed that since mid-2020 most offers for 2022 supply in the southern states were between the LNG netback price and the buyer alternative price. Despite a forecast shortage in the southern states in 2022 and the expected 2022 netback price rising significantly, prices offered for 2022 supply clustered around seller alternative levels in mid-2021 for the first time since the beginning of the Inquiry.

Between March and August 2021, 145 offers were priced below the expected LNG netback level with 74% for a supply term of two years or less. By comparison, only 8 offers fell below the expected LNG netback price during the corresponding period in 2020.

Average prices agreed by producers for delivery in the southern states in 2022 decreased to $8.56/GJ under gas supply agreements (GSAs) executed between March and August 2021. In contrast, average prices agreed by retailers for delivery in the southern states in 2022 increased to $8.22/GJ under GSAs executed over the same period.

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3 The buyer alternative price is the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the buyer’s location. It represents a ceiling in gas price negotiations (see Appendix B).

4 The seller alternative price is the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher). It represents a floor gas price in negotiations (see Appendix B).
The level of flexibility afforded under GSAs for supply in 2022 appears largely unchanged since our July 2021 report, with contracts executed by retailers in the southern states providing more flexibility on average than those executed by producers in the southern states and in Queensland. We will continue to assess the level of flexibility in GSAs in our upcoming reports in light of continued concerns raised by C&I users.

Under the HoA, LNG exporters have committed to not offer uncontracted gas (spot cargoes) to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market. The LNG exporters also committed that individual prices offered to domestic gas users will be internationally competitive.

Between 26 February and 12 August 2021, the LNG exporters sold 3 spot or additional LNG cargoes to the international market, totalling around 12 PJ. This is lower than the 14 spot cargoes (totalling 53 PJ) sold between 1 September 2020 and 26 February 2021 as reported in July 2021.

Since our July 2021 report, LNG producers have improved their documentation of offers made to the domestic market for exported uncontracted gas. However, we continue to hold concerns about how some LNG producers have approached demonstrating compliance with the HoA.

In particular:

- That some gas originally offered in some EOI processes was not ultimately able to be supplied to domestic customers and whether reasonable notice was provided.
- Many domestic offers from LNG producers do not appear to have been internationally competitive, and some exporters have provided insufficient information regarding their consideration of LNG prices when making domestic offers. (We note that many of these offers, while cited to demonstrate HOA compliance for gas exported in 2021, were made before the signing of the January 2021 HOA when the requirement to have regard to LNG prices was not yet in place).

We also have some concern that an exporter's reliance on short term offers made to the Wallumbilla Gas Supply Hub may not meet the needs of many domestic buyers, who often need longer term contractual certainty of supply.

We will maintain our close monitoring and expect LNG producers to continue to improve their HoA compliance in the future.

**Supply should be sufficient to meet forecast demand in 2022, but the long-term outlook has deteriorated particularly in the southern states**

Chart 3 sets out the forecast supply-demand balance in the east coast for 2022. It shows that supply from 2P reserves in the east coast (1,976 PJ) is expected to be sufficient to meet forecast domestic and contracted LNG export demand under long-term supply agreements (1,846 PJ) in 2022. It also shows that LNG producers expect to have 122 PJ of gas available in excess of their contractual commitments in 2022. This gas could be exported, placed into storage or utilised to supply the domestic market. If it is all exported, there would be a surplus of 9 PJ in the east coast market, which represents just 0.5% of total forecast supply.
The LNG producers expect to take more gas out of the domestic market than they expect to supply in 2022, which we first reported on in July 2021. While the LNG producers forecast to supply 160 PJ into the domestic market, they expect to withdraw 27 PJ more from the domestic market with 187 PJ of third party purchases.

The LNG producers forecast domestic supply of 160 PJ for 2022 is:

- 52 PJ less than the quantity they forecast to supply for 2021 as reported in January 2021, and
- 50% less than actual supply into the domestic market in 2017 and 2018, respectively.

There has been a downward trend in the quantities supplied by the LNG producers into the domestic market.
In contrast to the overall east coast market, the southern states are expected to experience a shortfall in supply from 2P reserves of 10 PJ in 2022. Queensland, on the other hand, is expected to have a 19 PJ surplus. The southern states will therefore be reliant on gas flowing from the north in order to avoid a shortfall.

The supply outlook in the southern states has deteriorated since our July 2021 interim report, primarily as a result of gas from the Cooper Basin being redirected into Queensland. This has contributed to an improvement in the supply outlook in Queensland in 2022, which has been further bolstered by a 10 PJ (15%) downward revision to GPG demand forecasts for Queensland.\(^5\)

While in aggregate there should be sufficient gas in Queensland to address the projected shortfall in the south, the need to transport more gas south may put upward pressure on the prices paid for gas in the south.

Beyond 2022, the long-term supply outlook (2023 to 2033) remains tight and uncertain, with forecast production from 2P reserves not expected to be sufficient to meet domestic demand and long-term LNG export demand in the east coast from 2026. This can be seen in chart 5. This is now the third year we have reported a reduction in production from forecast 2P reserves.

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\(^5\) Arising as a result of a correction to AEMO's GPG forecasts.
The position is even worse in the southern states, where a shortfall in supply from 2P reserves is expected to continue into 2023 and grow over the forecast period as a result of a significant reduction in 2P reserves in the southern states. The shortfall in the southern states is expected to occur two years earlier than we previously predicted. This acceleration appears to have occurred as a result of delays in bringing new sources of supply online and a general reduction in forecast production from 2P reserves in the Gippsland and Cooper basins.

In Queensland, a shortfall in supply from 2P reserves is not expected to arise until 2028, which is one year earlier than was previously forecast. This acceleration also appears to have occurred as a result of delays in bringing new sources of supply online and the significant write-down of 2P reserves that have occurred, particularly in the fields controlled directly or indirectly by some of the LNG producers.
Timely development of new supply and associated infrastructure is required to avoid future supply shortfalls

To address the projected shortfalls in supply (from 2P reserves), additional supply will be required, which could come from:

- the production of possible reserves, contingent and/or prospective resources, which are inherently less certain and more speculative than 2P reserves. They are also likely to face a range of technical and commercial challenges because they are largely located in CSG and other unconventional fields that are not yet in production or approved for development

- the construction of one or more LNG import terminals, the development of which are also currently subject to some uncertainty with final investment decisions to proceed with all elements of the project yet to be made by any of these projects.

Some of the shortfall could also potentially be met by natural gas alternatives, such as biomethane, natural gas-hydrogen blends, pure hydrogen or electrification over the longer-term. The use of these alternatives is driven in part due to global commitments to reach net-zero emissions by 2050. However, the timing of uptake and associated impacts on the east coast gas market remains uncertain (see box 1.2 for further discussion).

In the southern states, there are a number of new domestic supply projects that could potentially be brought online, but none have yet been approved for development. Most of the projects are also quite speculative in nature and have been subject to delays. There is a risk therefore that some projects will not come online in time (if at all) and those that do will not be sufficient to alleviate the projected shortfall in the south.

Additional supply from an LNG import terminal in the south, or more domestic supply from the north will therefore be required to address the projected shortfall in the south. It may also be necessary to divert some gas that would otherwise be exported into the southern states if new sources of supply cannot be developed rapidly enough. The HoA is currently due to expire on 31 December 2022. It would be prudent for the Australian Government to consider extending the HoA beyond 2022, given conditions are forecast to become more precarious in the east coast. We suggest that this occurs well in advance of the HoA expiring.

As noted above, construction has already begun on the LNG import terminal at Port Kembla. APA has also commenced work on expanding the capacity of the SWQP and MSP to enable more gas to flow from the north. Both projects are proposed to be completed in 2023, which could help to alleviate the shortfall in the south.

To address the projected supply shortfalls over the longer-term, there are a number of new domestic sources of supply that could potentially be brought online. This includes some large projects that are not yet connected to the east coast gas market (such as those in the Galilee, north Bowen and Gunnedah basins) and which will need to overcome a range of geological, commercial and regulatory barriers. Further, producers are finding it increasingly difficult to obtain finance to invest in fossil fuel projects.

Significant investment in upstream infrastructure and pipelines will also be required. There are also a number of other LNG import terminals proposed to be located in the southern states that could be brought online from mid-2023 onwards.

There are some positive signs for infrastructure investment, both in the short and longer-term. A number of infrastructure providers have announced intentions to expand the capacity of existing pipelines and to expand or develop new storage capacity. Infrastructure providers are also seeking out opportunities to work with suppliers to bring gas to market through the
construction of new pipelines and are considering a range of potential investments in upstream infrastructure.

We support governments in their work facilitating the timely and efficient development of new supply infrastructure and note recent measures like the Commonwealth Government’s National Gas Infrastructure Plan and Basin Development plans, and the Queensland Government’s Bowen Basin pipeline study.

**There are structural factors impeding upstream competition and/or the timing of gas being brought to market**

In January 2021 we announced our intention to undertake a review of upstream competition and the timeliness with which gas is brought to market. This review is being undertaken in response to concerns raised throughout the Inquiry about the degree of concentration in this part of the market and the structural and behavioural factors that may be impeding competition or limiting gas supply.

The need for the review has been reinforced by:

- the pricing behaviour we have observed over the course of the Inquiry
- our review of suppliers' pricing strategies, which indicates that competition is posing little constraint on producers' pricing decisions
- C&I user surveys we have undertaken, which have consistently raised concerns about the lack of effective upstream competition and the adverse effect this has on selling practices, gas prices and non-price terms and conditions in GSAs.

The review is being undertaken in two stages:

- Stage 1, which we have now completed, has focused on the structural factors that may be impeding competition or the timeliness of supply. This includes government processes and the barriers faced by producers when developing tenements.
- Stage 2, which we are undertaking in 2022. This will focus on behavioural factors that may be impeding competition or the timeliness of supply, such as joint venture arrangements, marketing arrangements, mergers, exclusivity provisions and supply decisions.

We released an issues paper in September 2021 and obtained information from a sample of producers using our compulsory information gathering powers. Based on our review of this material and our analysis of the market, it appears there are a number of structural factors impeding both upstream competition and the timeliness with which gas is brought to market. It also appears that:

- Greater diversity and more timely supply could be encouraged through changes to the processes used by governments when releasing acreage and when approving, monitoring and enforcing compliance with work programs.
- Upstream competition and the timeliness of supply could be significantly improved by reducing the infrastructure, regulatory and capital barriers faced by producers. It could also be improved if owners of existing upstream infrastructure provided third party access to this infrastructure on reasonable terms.

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We therefore recommend:

- **State, territory and Commonwealth governments:**
  
  - not grant acreage to producers with substantial existing acreage unless satisfied it will not affect the timing of their development of existing or new acreage
  
  - follow Queensland’s lead and consider both the diversity of suppliers and the efficiency with which gas can be brought to market, alongside the technical and financial capabilities of tenderers
  
  - proactively encourage gas to be brought to market in a timely manner through the adoption of shorter timeframes, where appropriate, and greater oversight of work programs.

- **Steps be taken by governments to reduce the infrastructure, capital and regulatory barriers faced by producers by:**
  
  - considering the implementation of a third party access regime for upstream infrastructure (including gathering pipelines, natural gas processing, water treatment and compression facilities) and storage facilities that, like the lighter form of regulation that applies to gas pipelines, would provide for recourse to a commercially-oriented dispute resolution mechanism if an access dispute arises
  
  - removing duplication in the regulatory approvals processes (particularly between the Commonwealth and state/territory governments), addressing limitations and uncertainties in these processes and helping producers to better navigate these processes.

We also note the Australian government’s efforts to help reduce the capital barriers faced by producers, by enabling market participants and financiers to make more informed investment decisions and encouraging more market-driven investment through measures such as the Strategic Basin Plans and National Gas Infrastructure Plan.

Our recommendation that governments consider implementing a third-party access regime for upstream infrastructure stems from stakeholder concerns about the significant barrier that access to infrastructure can pose (and has posed) for smaller producers and producers in more marginal fields. This is likely to become more of a constraint on the development of gas in the future, given the increasing reliance of the market on more marginal fields. There are also important parallels between storage facilities, gas pipelines and upstream infrastructure, in terms of the natural monopoly characteristics that they exhibit and the market power that the owners can wield.

**Most transport and storage prices continue to increase, emphasising the importance of upcoming regulatory reforms**

Table 1 sets out the minimum and maximum prices paid by shippers for firm forward haul services and the standing prices for this service as at July 2021. It shows that:

- the prices paid by shippers for firm forward haul transportation services on most pipelines generally increased in line with inflation between January 2021 and July 2021, with some exceptions (see blue and dark orange shaded cells)

- the standing prices published by pipeline operators increased in line with inflation on pipelines operated by APA, but otherwise remain unchanged.
Table 1: Firm forward haul service prices as at July 2021.

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Price ($/GJ as at July 2021)</th>
<th>Price change between January 2021 and July 2021 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>AGP</td>
<td>0.421</td>
<td>0.707</td>
</tr>
<tr>
<td>NGP</td>
<td>2.060</td>
<td>2.331</td>
</tr>
<tr>
<td>CGP</td>
<td>1.242</td>
<td>1.261</td>
</tr>
<tr>
<td>QGP (to Gladstone)</td>
<td>0.710</td>
<td>1.332</td>
</tr>
<tr>
<td>RBP Eastern haul</td>
<td>0.440</td>
<td>0.942</td>
</tr>
<tr>
<td>RBP Western haul</td>
<td>0.623</td>
<td>0.702</td>
</tr>
<tr>
<td>SWQP Western haul</td>
<td>1.007</td>
<td>1.428</td>
</tr>
<tr>
<td>SWQP Eastern haul</td>
<td>0.946</td>
<td>1.337</td>
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<tr>
<td>MAPS Southern haul</td>
<td>0.725</td>
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<tr>
<td>PCA (SEAGas)</td>
<td>0.575</td>
<td>0.793</td>
</tr>
<tr>
<td>EGP</td>
<td>0.981</td>
<td>1.332</td>
</tr>
<tr>
<td>MSP (Culcairn to Sydney)</td>
<td>0.421</td>
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<tr>
<td>MSP (Moomba to Sydney)</td>
<td>0.762</td>
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</tr>
<tr>
<td>TGP</td>
<td>1.396</td>
<td>2.660</td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data supplied by pipeline operators and standing price data from pipeline operator websites.

Note: Pipeline operators escalate their standing prices at the beginning of the calendar year. In addition to this, APA adjusts its prices quarterly in April, July and October. Minimum and maximum prices change frequently based on GTAs that have either commenced, expired or been varied during the relevant period.

Since our July 2021 report, the lowest price paid for firm forward haul services on the Amadeus Gas Pipeline (AGP) has fallen by approximately 26%. Conversely, the highest price paid for firm forward haul services on the Roma to Brisbane Pipeline (RBP) western haul increased by 12%, and the highest price paid for firm forward haul services on the Tasmanian Gas Pipeline (TGP) has increased by 5.3%. These changes are described further in chapter 6.

Like firm forward haul services, the prices paid by shippers for as available and interruptible transportation services on most pipelines have also increased in line with inflation over the last year, again with some exceptions.

In contrast to transportation prices, storage prices at the Iona underground storage facility have remained steady since our July 2021 report. Prices at the Dandenong LNG storage facility, on the other hand, have increased, with the fixed prices increasing by 8%-46%, while variable (liquefaction) charges converged towards the upper end of previously reported maximum prices.
The relatively steady transportation and storage prices we have seen over the course of the Inquiry reinforce the need for effective regulation to address monopoly pricing and ensure access to key transport and storage infrastructure.

Uncontracted capacity remains limited on key pipelines required to transport gas south (including the SWQP and Moomba to Adelaide Pipeline System), and access to storage and necessary compression services can also be limited. This could affect the ability of some shippers in the southern states to transport more gas from the north. Plans to expand capacity on the SWQP and MSP from 2023 will help ease these constraints.

Higher than efficient transportation costs and limited service flexibility could also affect the ability of shippers in the southern states to transport more gas from the north. Shippers continue to raise concerns with us about high transportation prices, limited service flexibility and contracted but unutilised capacity. They have also expressed concerns about the limited bargaining power they have in negotiations with pipeline operators.

Existing pipeline regulation can help improve outcomes for shippers, but only if there is widespread compliance by pipeline operators. We welcome the AER’s announcement that ensuring compliance with these obligations is a key compliance and enforcement priority for 2021-22.

Upcoming changes to gas pipeline regulatory framework are expected to pose more of a constraint on monopoly pricing and other exercises of market power by pipeline operators. The ACCC remains concerned with the South Australian Government’s proposed derogation from individual price reporting requirements, noting that it appears counter to the interests of South Australian users. The ACCC will continue to monitor these developments.

**Future work of the Inquiry**

We expect to provide our next interim report in July 2022. We will provide updates on:

- the prices offered and agreed for gas supply for 2022 and 2023
- the gas supply outlook for 2023
- the C&I gas user experience, and
- the pricing of firm forward haul transportation.

We also expect to report further on our examination of upstream competition and the timeliness with which gas is brought to market.

We will continue publishing the LNG netback price series and make information available and policy recommendations where we consider it appropriate and necessary.

Our priorities over the next 12 months will be to:

- monitor and report on compliance with the HoA signed with LNG producers
- examine the behavioural factors that may be contributing to the lack of effective upstream competition and/or affecting the timeliness with which gas is brought to market
- begin publishing longer-term forward LNG netback prices based on an oil index, and
- monitor and report on the implementation and operation of the voluntary industry code of conduct.
1. Supply and demand outlook

1.1. Key Points

• In 2022, supply from 2P reserves should be sufficient to meet forecast domestic and LNG export demand under long term supply purchase agreements (SPA) across the east coast gas market.

• Total supply in the east coast in 2022 is expected to be 1,976 PJ while domestic demand and LNG export demand under long term SPAs is expected to be 1,846 PJ.

• The supply-demand balance in the southern states has deteriorated since our July 2021 interim report, but improved in Queensland.

• A shortfall of 10 PJ is forecast in 2022 in the southern states, while a surplus of 19 PJ is forecast in Queensland. The southern states will be reliant on gas from the north being directed south in order to avoid a shortfall.

• LNG producers expect to have 122 PJ of gas available in excess of their contractual commitments in 2022. If produced, this gas could be exported, put in storage, or sold domestically. If it is all exported, there would be a small surplus of 9 PJ in the east coast representing less than 1% of total gas supply.

• The improvement in Queensland largely stems from a 10 PJ (~15%) correction in AEMO’s original GPG demand forecasts.

• LNG producers expect to take 27 PJ more gas out of the domestic market than they expect to supply into it. This has been driven by a continuing downward trend in quantities supplied into the domestic market by LNG producers since 2017. For 2022, 160 PJ is expected to be supplied by the LNG producers under domestic gas supply agreements, which is around 50% less than the quantities actually supplied in 2017 and 2018.

• Over the longer term (2023 to 2033) forecast production from 2P reserves is expected to be insufficient to meet east coast demand from 2026. While this is consistent with previous reports, there have been some notable changes:
  o In the southern states, the shortfall in 2022 is now expected to continue into 2023 and grow over time. This is earlier than our 2021 long term outlook, where the southern states were expected to first experience a shortfall in 2024. This is largely due to a significant reduction in production from 2P reserves.
  o In Queensland, a shortfall is expected to arise in 2028. Previously, this was expected in 2029.

• The acceleration of when shortfalls will occur is mostly due to delays in bringing new supply online and large write-downs of 2P reserves since 2017 (~8,955 PJ or 21%), primarily in fields controlled directly or indirectly by LNG producers.

• The shortfall in the south could potentially be alleviated in mid 2023 if the LNG import terminal in Port Kembla is developed and operational by this time. However, additional supply from the north may also be required.

• However, a number of gas alternatives are expected to be introduced during this period which may alleviate some of the projected shortfall from 2030 onwards.

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8 The LNG producers have agreed under the HoA with the Commonwealth government that uncontracted gas (spot cargos) will not be offered to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market.

9 The term ‘write-down’ is used in the chapter to jointly refer to reserves downgrades and other downward revisions.
If new supply cannot be developed rapidly enough, it may be necessary to divert gas into the domestic market that would otherwise be exported. As conditions become more precarious, it would be prudent for the Australian Government to consider extending the HoA well in advance of its expiration on 1 January 2023.

1.2. Introduction

This chapter provides an overview of the short and long term outlook for supply and demand. Forecasts are provided for the east coast gas market as a whole and disaggregated for Queensland and the southern states.

The short term outlook focuses on the 2022 supply year and compares:

- total forecast supply (production from east coast 2P reserves, storage withdrawals, and expected gas flows from the Northern Territory to Queensland), with
- total forecast demand (domestic demand plus the quantities of gas required by the LNG producers to meet their long term LNG SPA commitments).

The demand forecast also includes the quantity of gas that the LNG producers expect to produce in excess of their contractual commitments in 2022.

The long term outlook focuses on forecast supply and demand for the supply years 2023 to 2033. The long term supply outlook includes forecast production from the Bowen (including the north Bowen), Surat, Galilee, Cooper, Gippsland, Bass, Otway, Gunnedah, and Sydney basins. Production from the Northern Territory is included via expected flows from the Northern Territory into the east coast.

The long-term supply outlook does not include forecast production from the Clarence-Moreton, Isa Super or McArthur (including the Beetaloo sub-basin) basins, because there are currently no 2P reserves in these basins and no forecast production from possible reserves, contingent or prospective resources.

The supply and LNG demand data used in this chapter were obtained directly from producers in response to compulsory information notices issued in August 2021. Producers provided forecast production quantities from developed and undeveloped 2P reserves, possible reserves, contingent and prospective resources and forecast flows from the Northern Territory into Queensland. The LNG producers also provided forecast estimates of LNG export demand under long term supply agreements and projected LNG spot sales.

The long term supply outlook reflects information that producers provided on their reserves and resources in the east coast and onshore Northern Territory as at 30 June 2021, and a range of other information provided on the development of gas fields and potential barriers to the development of resources. This information is examined in detail in Appendix A and summarised in box 1.1.

The domestic demand forecast used for both the short and long term outlook is based on AEMO's March 2021 Gas Statement of Opportunities (GSOO) Central scenario. We understand that AEMO is currently working on its next GSOO and that this will include further consideration of the impact of electrification on demand, which could result in a reduction in the demand forecasts over the medium to longer term. The next GSOO is expected to be published in March 2022.

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10 AEMO (2021) ‘Gas Statement of Opportunities (GSOO)’ [online document], AEMO.
1.3. **East coast gas market supply should be sufficient to meet expected demand for the 2022 supply year**

Chart 1.1 illustrates the forecast supply-demand balance in the east coast for the 2022 supply year.

It shows that supply from 2P reserves in the east coast (1,976 PJ) is expected to be sufficient to meet forecast domestic and contracted LNG export demand under long-term supply agreements (1,846 PJ) in 2022. It also shows that LNG producers expect to have 122 PJ of gas available in excess of their contractual commitments in 2022. This gas could be exported, placed into storage or utilised to supply the domestic market. If it is all exported, there would be a surplus of 9 PJ in the east coast market, which represents a buffer of just 0.5% assuming all the excess gas is exported.

Since our July 2021 interim report, total forecast supply for 2022 has fallen by 5 PJ (from 1,981 PJ to 1,976 PJ). This can largely be attributed to the reduction in forecast production from 2P reserves, which has fallen by 11 PJ (from 1,955 PJ to 1,944 PJ). The reduction in forecast production has been offset somewhat by expected net withdrawals from storage facilities, which have increased by 5 PJ (from 12 PJ to 17 PJ). Based on storage levels, storage facilities could supply up to an additional 47 PJ in 2022 if required.

Northern Territory production is expected to contribute 15 PJ to the east coast in 2022. This forecast has not changed since the July 2021 interim report and represents around 40% of the capacity of the Northern Gas Pipeline (NGP) that connects Tennant Creek in the Northern Territory and Mt Isa in Queensland.
Chart 1.1: 2022 forecast supply-demand balance in the east coast

<table>
<thead>
<tr>
<th>Supply</th>
<th>Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNG producers’ excess gas</td>
<td>15</td>
</tr>
<tr>
<td>Quantity required to meet long term LNG SPAs</td>
<td>93</td>
</tr>
<tr>
<td>Domestic demand (GPG)</td>
<td>1851</td>
</tr>
<tr>
<td>Domestic demand (Residential, commercial, industrial)</td>
<td>468</td>
</tr>
<tr>
<td>Northern Territory supply</td>
<td>64</td>
</tr>
<tr>
<td>Net storage withdrawals</td>
<td></td>
</tr>
<tr>
<td>Production from undeveloped 2P reserves</td>
<td></td>
</tr>
<tr>
<td>Production from developed 2P reserves</td>
<td></td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data obtained from gas producers as at August 2021 and of domestic demand from AEMO’s March 2021 GSOO. We note AEMO’s GPG demand as published in its March 2021 GSOS has been corrected from 74 PJ to 64 PJ. This update is reflected on AEMO’s forecasting portal available here: http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total

Notes: Totals may not add up due to rounding. The quantity required to meet the long term LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG, which for 2022 is expected to total 103 PJ. Total demand includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments for 2022 (which could either be exported or supplied to the domestic market).

Chart 1.1 does not include production from possible reserves, contingent or prospective resources as these sources are more speculative. However, producers have indicated they may produce an additional 64 PJ from possible reserves and contingent and prospective resources in 2022.

GPG demand continues to be volatile and difficult to predict. Since our July 2021 interim report, AEMO has corrected its GPG demand forecast for 2022 which has resulted in a reduction in demand in Queensland.

The LNG producers continue to play a significant role in the east coast gas market and in turn the supply-demand balance. Table 1.1 compares the LNG producers’ forecast supply-demand balance for 2022 that was reported in our July 2021 interim report with the most recent estimates provided by the LNG producers.

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11 AEMO, Gas statement of opportunities, March 2021. Consistent with the approach taken by AEMO in its 2018 GSOS, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

12 AEMO’s original GPG forecast for 2022 of 74 PJ was used in our July 2021 report.
Table 1.1 Forecast supply-demand balance of LNG producers in 2022 (PJ)

<table>
<thead>
<tr>
<th></th>
<th>Reported in July 2021</th>
<th>Most recent estimate</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Supply</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production from 2P developed reserves and forecast storage withdrawals</td>
<td>1,299</td>
<td>1,376</td>
<td>+77</td>
</tr>
<tr>
<td>Production from undeveloped 2P reserves</td>
<td>106</td>
<td>33</td>
<td>-73</td>
</tr>
<tr>
<td>Third party purchases</td>
<td>196</td>
<td>187</td>
<td>-9</td>
</tr>
<tr>
<td>Total supply available to LNG producers</td>
<td>1,601</td>
<td>1,595</td>
<td>-6</td>
</tr>
<tr>
<td><strong>Contracted Demand</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Quantity required to meet domestic GSAs</td>
<td>159</td>
<td>160</td>
<td>+1</td>
</tr>
<tr>
<td>Quantity required to meet long term LNG SPAs</td>
<td>1,341</td>
<td>1,314</td>
<td>-27</td>
</tr>
<tr>
<td>Total contracted demand</td>
<td>1,500</td>
<td>1,474</td>
<td>-26</td>
</tr>
<tr>
<td><strong>Excess gas and contribution to east coast</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excess gas (total supply - contracted demand)</td>
<td>101</td>
<td>122</td>
<td>+21</td>
</tr>
<tr>
<td>LNG producers' net contribution to east coast (total domestic GSAs - third party purchases)</td>
<td>-37</td>
<td>-27</td>
<td>+10</td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data obtained from LNG producers as at March 2021 and August 2021.

Note: Totals may not add up due to rounding. The quantity required to meet the long LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG. In 2022 this usage is expected to total 103 PJ.

As table 1.1 shows, LNG producers expect to have sufficient gas available to meet their contractual obligations under domestic GSAs and long term LNG SPAs in 2022 and have forecast they will produce 122 PJ of excess gas.

The amount of excess gas LNG producers expect to have in 2022 is 21 PJ higher than what was reported in our July 2021 report. This increase can largely be attributed to the 27 PJ reduction in the amount of gas that the LNG producers expect to require to meet their long term LNG SPAs.

The LNG producers expect to take more gas out of the domestic market than they expect to supply in 2022, which we first reported on in July 2021. While the LNG producers forecast to supply 160 PJ into the domestic market, they expect to withdraw 27 PJ more from the domestic market with 187 PJ of third party purchases.

Analysis covering the 2017 to 2022 period reveals a concerning downward trend in the amount of gas supplied into the domestic market by the LNG producers. This downward trend is the key driver behind the LNG producers’ deteriorating net contribution over the period, which has now become particularly pronounced in their 2022 forecasts. This is illustrated in chart 1.2 below.
In each year over the 2017 to 2020 period, actual quantities supplied by the LNG producers into the domestic market were between 261 PJ and 333 PJ.

For 2022, the expected domestic supply from the LNG producers of 160 PJ is around 50% less than actual supply into the domestic market in 2017 and 2018, respectively. While the quantities withdrawn from the domestic market under third party purchases have also reduced over the 2017 to 2022 period, it has not been sufficient to offset the decline in domestic supply. This can be seen in the declining net contribution of the LNG producers in chart 1.2 above.

This rapid and significant reduction in domestic supply from the LNG producers has contributed to the tight and uncertain conditions in the domestic market as well as the increase in their forecast excess gas.

The forecast excess gas could be placed into storage, used to supply the domestic market, or exported as spot cargoes. If international market conditions are favourable, the LNG producers may seek to sell their excess gas as LNG spot cargoes. The capacity of the export facilities is sufficient to process the quantity of gas required to meet their LNG SPAs as well as their excess gas sold as LNG spot cargoes. If the LNG producers export all their forecast excess gas, a surplus of 9 PJ is forecast across the east coast gas market (see chart 1.1).

As discussed in chapter 4, the LNG producers have agreed under the HoA with the Australian Government that uncontracted gas (spot cargoes) will not be offered to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the domestic market. The fact the LNG producers are expecting to supply approximately half the amount of gas into the domestic market in 2022 than they supplied on average between 2017 and 2019 highlights the continuing importance of this agreement to ensure that sufficient gas supply is available to the domestic market. Our observations on LNG producers’ compliance with the HoA are discussed in further detail in chapter 4.
1.3.1. The southern states could experience a supply shortfall in 2022

A supply shortfall is expected in the southern states in 2022, with demand expected to exceed supply from 2P reserves by 10 PJ.

The overall demand forecast for 2022 is unchanged from our July 2021 interim report. Forecast supply, however, is 4 PJ lower. This is primarily a result of a change in where gas from the Cooper Basin is expected to be supplied in 2022, with 5 PJ of gas previously identified for supply to the southern states now expected to be supplied to Queensland. This change has been offset somewhat by a 1 PJ increase in supply from 2P reserves in the southern states.

Production from possible reserves and contingent resources in 2022 has not been included in chart 1.3 due to the uncertainties associated with their development. Producers in the southern states have informed us they expect to produce 3 PJ of gas from possible reserves in 2022. Producers in the Cooper Basin, on the other hand, expect to produce an additional 25 PJ from possible reserves and contingent and prospective resources in 2022. However, it is unclear whether this gas would be supplied into Queensland or the southern states.

As noted in July 2021, gas producers’ forecasts of available annual production in 2022 provided to AEMO suggest that a maximum of 445 PJ could be supplied in the southern states. Additional supply may therefore be available in the south, depending on producers' operational limitations and the economics of bringing this extra gas to market.

If southern producers do not increase production, the southern states will be reliant on surplus gas from Queensland being directed south. AEMO’s forecast of north-south transportation capacity suggest there should be sufficient capacity in 2022 to enable gas to be supplied from Queensland to the southern states (particularly to meet peak winter demand). Gas swaps could be used between Queensland suppliers and suppliers in either the Cooper Basin or elsewhere in the south to meet demand in the southern states and avoid the need to use transportation capacity.

After 2022, the deterioration in supply conditions in the southern states is expected to continue, with 2022 marking the beginning of the structural shortfall. This is discussed in further detail in section 1.4.2.

The shortfall in the southern states may result in buyers having to source gas from the north and pay the costs of transporting the gas south. The lack of supply alternatives in the south means that the price paid for gas in the south may be influenced by the buyer alternative price. This is substantially higher than the seller alternative, which is the price that would prevail if there was sufficient supply and diversity of supply in the south. For further discussion on this issue, please refer to section 4.4.3.

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13 AEMO (2021) GSOO; Table 7, Forecast of available annual production as provided by gas producers.
14 AEMO (2021) GSOO.
15 The buyer alternative price is the LNG netback at Wallumbilla plus the cost of transporting gas south.
16 The seller alternative price is, the higher of, the LNG netback at Wallumbilla less the cost of transporting the gas north and the forward cost of production.
Chart 1.3: 2022 forecast supply-demand balance in southern states

Source: ACCC analysis of data obtained from gas producers as at August 2021, and of the domestic demand forecast (Central scenario) from AEMO’s 2021 GSOO.\(^{17}\)

Notes: Totals may not add up due to rounding. Supply data does not include potential supply volumes from Queensland.

1.3.2. Queensland should have sufficient gas in 2022

Chart 1.4 shows the expected supply-demand balance in Queensland (including supply from the Northern Territory) for 2022. A supply surplus is expected in Queensland in 2022, with supply from 2P reserves expected to exceed demand by 19 PJ if LNG producers sell all their excess gas as spot LNG cargoes internationally.

\(^{17}\) Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has attributed domestic demand attributed to losses with the residential, commercial and industrial categories.
Compared to our July 2021 interim report, the supply-demand balance in Queensland has improved, with the forecast surplus growing by around 16 PJ. This can largely be attributed to the:

- 10 PJ reduction in AEMO’s GPG demand forecast
- redirection of 5 PJ of supply from the Cooper Basin into Queensland.

While not shown in the chart, producers in Queensland expect to produce less from possible reserves and contingent resources compared to the July 2021 interim report. Previously they forecast supply of 69 PJ from these sources, but they are now forecasting 37 PJ of gas to be produced from these sources.

Source: ACCC analysis of data obtained from gas producers as at August 2021, and of the domestic demand forecast (Central scenario) from AEMO’s 2021 GSOO.18

Notes: Totals may not add up due to rounding. The quantity required to meet the long LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG. In 2022 this usage is expected to total 103 PJ. Total demand in Queensland includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments in 2022 (which if produced could either be exported or supplied to the domestic market).
1.4. The long term supply outlook has deteriorated and supply shortfalls are expected unless new supply is brought online

In addition to examining the supply-demand outlook for 2022, we have examined the long term supply outlook for the period 2023-2033. The last time we reported this was in our January 2021 interim report. At the time we observed that the long term supply outlook was tight and uncertain, with the potential for a shortfall in supply to emerge in the east coast by 2026. On a regional basis, we found that a shortfall in supply from 2P reserves in the southern states could emerge by 2024, while in Queensland a shortfall was not expected to emerge until 2029.

Little has changed in the intervening period, with a supply shortfall still expected to emerge in the east coast gas market overall in 2026. However, the projected shortfall in supply from 2P reserves has been brought forward in the southern states by two years to 2022 and in Queensland by one year to 2028. The acceleration of the shortfalls in the southern states and in Queensland can largely be attributed to forecast reductions in production coming from undeveloped 2P reserves and delays in bringing some projects online.

Chapter 2 provides an overview of potential new sources of supply and infrastructure that producers, LNG import terminals and infrastructure providers have indicated could come online from 2022 to 2026 to help address the emerging supply shortfalls.

1.4.1. Supply from 2P reserves is expected to be sufficient to meet demand in the east coast until 2025, but a shortfall could emerge from 2026

Chart 1.5 shows the long term demand and supply outlook for the east coast gas market, with supply based on production from developed and undeveloped 2P reserves. Production from 2P reserves is expected to be sufficient to meet projected domestic demand and long term LNG export demand until 2026. From 2026 onwards the east coast gas market is expected to experience a shortfall in supply from 2P reserves unless additional supply comes online.
Chart 1.5: Forecast supply from 2P reserves and demand in the east coast, 2023-33

To address the projected shortfall, additional supply will need to be brought online

The additional supply required to meet demand that cannot otherwise be met by 2P reserves (‘unfulfilled demand’) from 2026 could come from:

- the development of possible reserves, contingent, and prospective resources in the Bowen, Surat, Galilee, Cooper, Gippsland, Bass, Otway and/or Gunnedah basins, and/or
- the development of one or more LNG import terminals in the southern states.

We note that the development of possible reserves and contingent and prospective resources is inherently less certain and speculative than supply from 2P reserves, with:  

- possible reserves being those additional reserves that analysis of geological and engineering data suggest are less likely to be recoverable than probable reserves

Source: ACCC analysis of data obtained from gas producers as at August 2021 and domestic demand from AEMO’s March 2021 GSOO.

Notes: Export demand includes feed gas requirements (such as fuel) required to produce LNG. Forecast spot and additional LNG sales represent flexible quantities that, if produced, could be exported, placed into storage, or sold to the domestic market. The maximum sustained LNG output capacity is based on the present point in time and does not account for potential unplanned maintenance, aging of facilities, changes in CSG feedstock or other factors that may affect capacity over the period.

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19 The long term supply outlook does not include forecast production from the Clarence-Moreton, Galilee, Isa Super or McArthur (including the Beetaloo sub-basin) basins, because there are currently no 2P reserves in these basins and no forecast production from possible reserves, contingent or prospective resources.

• contingent resources being those quantities estimated to be potentially recoverable but not yet commercial to develop, due to one or more contingencies (i.e. there is currently no viable market, or commercial recovery depends on technology or infrastructure)

• prospective resources being those quantities estimated to be potentially recoverable from undiscovered accumulations by the application of future development projects.

Further, the majority of possible reserves and resources are located in CSG and other unconventional gas fields that are not yet in production or approved for development. There is therefore a significant degree of uncertainty surrounding these potential sources of supply. (See also box 1.1). We also note that the exact timing and volume of supply from these sources is contingent on a number of geological, regulatory, infrastructure and commercial factors, some of which may result in projects not proceeding at all.

Like domestic sources of supply, the development of LNG import terminals and the volume of gas likely to be imported through this infrastructure is also dependent on commercial factors that are difficult to predict. The volume of LNG imported will, for example, depend on how the cost of importing gas and using the LNG import facilities compares to sourcing gas domestically. The other key uncertainty posed by the LNG import terminals at this stage, is that it is unclear how many LNG import terminals will actually be developed. What is clear, is that all of the five LNG import terminals that have been proposed will not be required, because if this was to occur the total LNG import capacity would exceed total domestic demand in the east coast (see section 2.4).

Of the five LNG import terminals that have been proposed, the Port Kembla terminal is the most progressed, with regulatory approvals obtained and construction of the terminal commenced (see section 2.4). While there is still some uncertainty surrounding whether this project will proceed, it is more advanced than the other four projects, which are yet to obtain regulatory approvals. Given the uncertainty surrounding the other four projects, chart 1.6 only includes the capacity associated with AIE’s proposed terminal.21

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21 Forecast annual capacity for the Port Kembla import terminal is assumed to be 65-90 PJ in 2023 and 130-180 PJ from 2024-2033.
Chart 1.6: Potential for other supply sources to meet unfulfilled demand in the east coast, 2023-33

As chart 1.6 shows, while production from possible reserves is significantly less certain than from 2P reserves, if produced, gas from these reserves could result in supply being sufficient to meet demand in the east coast until around 2028 (assuming no spot or additional LNG cargoes). If supply from contingent and prospective resources is also realised (which is a significant assumption given the highly speculative nature of this source of supply), then it could meet all of the unfulfilled demand over the period 2023 to 2033.

If the Port Kembla import terminal is developed and no additional supply comes from possible reserves, contingent or prospective resources, then gas from the terminal would be sufficient to meet demand in the east coast until at least the end of 2027 but potentially until the end of 2028 (assuming no spot or additional LNG cargoes are exported by the LNG producers). Additional supply from a combination of possible, contingent or prospective resources, or another import terminal would therefore be required to meet demand from 2028 or 2029 onwards.

While not shown in chart 1.6, supplying customers with a natural gas-hydrogen blend or with biomethane is currently being explored at a distribution level which if successful could reduce the amount of natural gas required to meet the demand of these customers. The cost of producing these alternative sources of supply is currently much higher than the cost of producing natural gas. However, if they become more commercially viable, then it is possible that over the longer term they could become a viable substitute in some situations, noting...
that not all natural gas users can use hydrogen even in a blended form. Further detail on these alternative sources of supply and the impact they could have on demand for natural gas is set out in box 1.2, along with an overview of the steps governments are taking to encourage their uptake.

**Box 1.1: Uncertainty in the supply outlook for domestic sources of supply**

Chart 1.6 sets out the producers’ estimates of their proved, probable and possible reserves and 2C contingent resources in the east coast and onshore Northern Territory.

**Chart 1.6: Snapshot of reserves and resources (as at 30 June 2021)**

![Chart showing reserves and resources](chart.png)

Source: ACCC analysis of data obtained from producers.

As this chart shows, as at 30 June 2021 there were:

- 33,213 PJ of 2P reserves, the majority of which are located in Queensland, with 70% located in the Surat Basin and 18% in the Bowen Basin. The remainder are located in Victoria (8%), the Cooper Basin (3%) and the Amadeus Basin (0.7%).

- 38,986 of 2C resources, the majority of which are also located in Queensland, with 34% located in the Bowen Basin, 21% in the Surat Basin and 7% in the Galilee Basin. The McArthur Basin also contains a significant quantity of 2C resources (18%), while the Gunnedah Basin, Cooper Basin and Offshore Victoria Basins each account for 6–7% of 2C resources.

- The majority of 2P reserves (over 80%) and 2C resources (over 50%) continue to be controlled by LNG producers. APLNG, for example, controls 34% of 2P reserves, QGC controls 14% in its own right and has acquired the bulk of Arrow Energy’s 2P reserves (17%), and Santos-GLNG controls

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18%. While highly concentrated, an increasing number of junior producers are acquiring acreage and, in some cases, becoming upstream operators. This is a positive development that is being facilitated by some governments through their acreage release programs (see box 2.1 for more detail).

Consistent with the trend observed over the last three years, 2P reserves fell by over 1,393 PJ in the 12 months to 30 June 2021, while 2C resources rose by just 335 PJ.

Over the last four years, 2P reserves in the east coast have declined by around 23% and the long term supply outlook has become increasingly dependent on more speculative sources of supply, the development of which will face a number of challenges. Further detail on these sources of uncertainty is provided below and in Appendix A.

Reserves write-downs

In the 12 months to 30 June 2021, 2P reserves in the east coast and onshore Northern Territory were written down by around 1,117 PJ, the majority of which occurred in the Bowen and Surat basins (980 PJ) (see Appendix A). The write-down in the Surat and Bowen basins is significant and continues the trend observed in the last four years. 8,157 PJ of 2P reserves in these two basins have been written down since 2017, predominantly in fields controlled directly or indirectly by some of the LNG producers. This accounts for over 90% of the total write-down of 2P reserves that has occurred since 2017.

This write-down highlights the uncertainty surrounding the long term performance of CSG fields and the significant technical challenges that producers can face, particularly when developing unconventional sources of gas. It could also reflect decisions on the part of some producers to ‘bank’ or ‘warehouse’ gas, or to withhold supply to maintain or raise prices, although we have not identified evidence of this to date. The ACCC is examining this as part of its review of upstream competition and the timeliness of supply (see chapter 3).

Increasing reliance on more speculative sources of supply

With 2P reserves declining, the long term security of supply in the east coast is becoming increasingly dependent on CSG and other unconventional sources of supply, the development of which, as noted above, can face a number of technical challenges. The supply outlook is also becoming more dependent on undeveloped reserves and resources, with information provided by producers indicating that (see table A.4 in Appendix A):

- Over half the 2P reserves are undeveloped, most of which are located in CSG fields. In contrast to developed reserves, where gas is expected to be recovered from existing wells and facilities, further investment will be required to recover these undeveloped reserves.
- 100% of 2C resources are undeveloped, with 80% located in fields not yet in production or approved for development. Most of these resources are located in CSG and unconventional gas fields in the Bowen, McArthur, Galilee and Gunnedah basins, which are expected to face a number of technical and commercial barriers. It could therefore be some time before these resources are considered commercially recoverable and capable of being supplied into the market (if at all).

While reliance on more speculative sources of supply is an issue across the east coast, it is more pronounced in the southern states with 94% of 2C resources and 29% of 2P reserves located in fields that are not yet in production, or approved for development.
Box 1.2: Natural gas alternatives potential impact on demand

In the medium to longer term, a combination of hydrogen, biomethane and the electrification of existing gas appliances could lead to a decline in the demand for natural gas.

In its most recent Gas Statement of Opportunities, AEMO examined how increased hydrogen usage could affect the demand for natural gas. In short, AEMO found that if hydrogen was supplied via distribution pipelines and also used to supply some industrial demand, then the demand for natural gas in the east coast would be around:

- 4 PJ lower than what it would otherwise have been in 2023; and
- 61 PJ lower than what it would otherwise have been in 2033.

While the initial impact of hydrogen is expected to be relatively small, by 2030 increased use of hydrogen could start alleviating some of the projected shortfall in supply. It is not, however, expected to address the shortfall prior to this point. In November 2021 the AER released a stakeholder information paper that considers how the current energy transition affects regulated gas networks and implications for the economic regulation of gas pipelines and networks.

Government initiatives to facilitate the development of a hydrogen industry

In December 2018, Energy Ministers set out their vision for hydrogen, which was as follows:

“Our vision is to make Australia a major player in a global hydrogen industry by 2030.”

Energy Ministers also agreed to work together to develop and implement a national strategy, build hydrogen export markets and deliver domestic hydrogen projects (including potentially through the use of hydrogen in gas networks and hydrogen refuelling stations).

Dr Alan Finkel AO led the development of the Strategy, which was completed in late 2019 and set out a number of government actions to support the development of a hydrogen industry. The Strategy was endorsed by Energy Ministers on 22 November 2019. One potential area for domestic growth identified in the Strategy was to use ‘clean hydrogen’ (i.e. hydrogen produced using renewable energy or fossil fuels with substantial CCS) in gas distribution networks:

“Adding clean hydrogen in Australian gas distribution networks has advantages for stimulating early hydrogen demand growth. This is because governments can directly influence when and by how much demand for hydrogen is increased, whereas other sources of hydrogen demand depend on market uptake of hydrogen end-use technologies.”

To this end, the Strategy provides for governments to continue to support trials of hydrogen in gas distribution networks, where it is safe to do so. In contrast to gas distribution networks, the Strategy noted that governments would not support blending in existing transmission pipelines until further evidence emerges that hydrogen embrittlement can be safely addressed.

Following the release of the National Hydrogen Strategy, a number of distribution pipeline trial projects have been announced, including AGIG’s HyP SA, HyP Murray and HyP Gladstone projects and Jemena’s Western Sydney Green Gas Project. The Queensland, Tasmanian and South Australian governments have also respectively collaborated with Incitec Pivot, Neoen and Fortescue Future Industries to engage in feasibility studies and develop various industrial scale production facilities and hydrogen hubs.

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23 AEMO’s hydrogen scenario assumptions differ from the central scenario by considering:
- A thriving green hydrogen economy driving strong economic and population growth;
- Faster technological advancement and aggressive emissions reduction targets; and
- Hydrogen gradually replacing up to 20% of natural gas demand by 2040.


26 Ibid.

27 Ibid.

28 Ibid.
Other government initiatives to reduce the demand for natural gas

Over the last 12 months, a number of governments have announced initiatives that could result in a further reduction in the demand for gas.

The Victorian Government, for example, has published a gas substitution roadmap consultation paper which seeks to reduce its natural gas use through increased energy efficiency, electrification and substitution with alternatives such as hydrogen and biogas. Victoria has the largest domestic consumption of natural gas, so its efforts to reduce natural gas use could have a significant impact on total domestic natural gas demand.29

Similarly, the NSW Government has released a ‘future of gas statement’, which commits to a transition away from natural gas.30 Consistent with the ‘future of gas statement’, the NSW Government has announced its “NSW Hydrogen Strategy”, which it says will: 31

\[ \text{attract more than $80 billion of investment, drive deep decarbonisation and establish itself as an energy and economic superpower.} \]

NSW also has an ongoing energy savings scheme that includes the electrification of natural gas appliances.

Other state and territory government initiatives include:

- the ACT Government’s removal of the mandatory requirement for new homes to be connected to the mains gas network and its commitment that all new government offices and public school buildings will be completely electric
- the South Australian Government’s ‘Retailer Energy Productivity Scheme’, which promotes the electrification of natural gas appliances.

1.4.2. Shortfalls in supply from 2P reserves in the southern states are expected to continue in 2023 and grow over the forecast period

Chart 1.7 sets out the forecast supply and demand balance in the southern states between 2023 and 2033. This chart includes forecast production from developed and undeveloped 2P reserves in the Gippsland, Bass, Otway, Sydney, Gunnedah and Cooper basins. It does not, however, including any additional gas that could be supplied from possible reserves, contingent or prospective resources in these basins. Nor does it include any gas from the proposed LNG import terminals. These more speculative sources of supply are instead accounted for in chart 1.8.

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The shortfall in supply from 2P reserves observed in 2022 is expected to continue into 2023 and beyond. This is two years earlier than what we reported in our January 2021 interim report.

The acceleration of the shortfall appears to have occurred as a result of a substantial reduction in forecast supply from 2P reserves, which has been offset to some extent by a reduction in forecast demand. Esso operated fields in the Gippsland basin are a key contributor to the reduction in forecast supply in the southern states, which has in part resulted in the expected shortfall in southern supply occurring two years earlier than previously reported. There has also been a reduction in forecast production from 2P developed reserves in the Cooper and Otway basins, some of which may be attributable to the delays we have observed in new sources of supply coming online (see section 2.3).

Not only is the shortfall expected to continue over the forecast period, but it is also expected to grow over this time, as production from 2P reserves in the southern states falls from around 350 PJ in 2033 to around 70 PJ in 2033. This reduction is significant and can largely be attributed to declining production in the Gippsland Basin, with production from 2P reserves forecast to fall by around 60% between 2023 and 2028. While production from possible reserves and contingent and prospective resources is forecast to offset some of this decline, by 2028 it is expected that total production will be around 85 PJ per annum lower than what it is in 2023.

To address the projected shortfall in supply from 2P reserves, additional supply will be required. Chart 1.8 provides some insight into the potential sources of additional supply that could be brought online to meet the unfulfilled demand in the southern states from 2023.
As chart 1.8 shows, the reduction in supply from 2P reserves has resulted in the supply outlook in the south becoming more reliant on production from contingent and prospective resources and, to a lesser extent, possible reserves. If production from these sources is realised, it could result in supply being sufficient to meet forecast demand in the southern states until 2026. However, as noted in box 1.1, supply from these sources is less certain and more speculative in nature. The development of these sources of supply can also face significant technical and commercial challenges, which may result in some projects not proceeding at all, while those that do proceed may be delayed, or production may be lower than expected.

Given the risks associated with these developments, and the potential size of the shortfall, additional supply is expected to be required in the south to ensure that supply is sufficient to meet forecast demand. This could potentially come from:

- The development of the Port Kembla LNG import terminal, which, as noted above, is the most advanced of the LNG import terminals. If this terminal is developed and comes online in mid-2023 (as AIE has indicated), it could help to defer the projected shortfall in the southern states until later in the forecast period.

- Additional supply from domestic sources in the north. This has become more feasible following APA’s decision to expand the capacity of the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP) by around 25% by 2023.32

It may also be necessary to divert some of the gas that would otherwise be exported as LNG into the domestic market if new supply in the south cannot be developed rapidly enough to meet demand. Given the timing of project shortfalls, there may be a need for the Australian Government to extend the HoA with LNG producers beyond the current expiration date of

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32 APA (2021) ‘APA commences 25% expansion of east coast grid, enters into agreement with Origin Energy’ [ASX Announcement], APA.
1 January 2023, to ensure LNG producers continue to offer gas into the domestic market as conditions become more precarious.

These options are examined in more detail in chapter 2.

1.4.3. The longer term supply and demand outlook for Queensland has deteriorated but a shortfall is not expected until 2028

Chart 1.9 sets out the forecast supply and demand balance in Queensland between 2023 and 2033. This chart includes forecast production from developed and undeveloped 2P reserves, possible reserves, and contingent and prospective resources from the Bowen, Galilee, and Surat basins. It also includes expected flows from the Northern Territory into the east coast.

The supply and demand outlook is more favourable in Queensland than it is in the east coast, with production from 2P reserves expected to be sufficient to meet forecast domestic demand and long term LNG export demand until 2027, with a shortfall expected in 2028. This is one year earlier than we reported in our January 2021 interim report.

The acceleration of the supply shortfall in Queensland has occurred because the demand forecast for Queensland has increased and there has also been a reduction in forecast supply from 2P reserves. The reduction in supply from 2P reserves is primarily attributable to reductions in the forecast production of undeveloped 2P reserves from both the Bowen and Surat basins, which has more than offset the increased production from 2P developed reserves in the Surat Basin. The reduction in production from undeveloped 2P reserves appears to have occurred as a result of delays in a number of new sources of supply coming online (see section 2.3). It has also arisen as a result of the write-down in 2P reserves that has occurred in Queensland (see box 1.1).

If supply from possible reserves is realised, then this could be used to supply additional LNG cargoes (see dark orange dotted line in chart 1.9) or redirected to the southern states to help address the projected shortfalls in the south.
Chart 1.9: Forecast supply (including from the Northern Territory) and demand in Queensland, 2023-33

Source: ACCC analysis of data obtained from gas producers as at August 2021 and of domestic demand from AEMO's March 2021 GSOO.
2. Potential supply and infrastructure developments

2.1. Key Points

- New sources of supply and related infrastructure will be required to address the potential shortfall in supply from 2P reserves that is expected to arise from 2022 in the southern states, and by 2026 for the east coast.

- In the southern states, additional supply from either an LNG import terminal, or domestic supply sources in the north will be required.
  - There are a number of new domestic supply projects that could be brought online but the majority are located in Queensland and have not yet been approved for development. There is a risk that some projects will not come online in time (if at all) and those that do will not be sufficient to alleviate the projected shortfall; a large number of the projects are quite speculative and/or experienced delays.
  - Construction of the Port Kembla LNG import terminal has commenced, while other import terminal projects are at an earlier stage of development, with some yet to achieve Final Investment Decision (FID). The Port Kembla project is estimated to come online by mid-2023 and should have sufficient capacity to address the projected shortfall in the south and the broader east coast market until 2028.

- To address projected supply shortfalls over the longer-term, there are a number of new domestic supply sources and LNG import terminals that have not yet been approved that could potentially be brought online.
  - New domestic sources include some large projects not yet connected to the east coast market (such as the Galilee, north Bowen and Gunnedah basins and the Beetaloo sub-basin), which will need to overcome a range of geological, commercial and regulatory barriers. Significant investment in upstream infrastructure and pipelines will also be required.

- There are positive signs for infrastructure investment, both in the short and longer-term.
  - A number of infrastructure providers have announced intentions to expand the capacity of existing pipelines and to either expand or develop new storage capacity in the next two years. This includes the southbound capacity of SWQP and MSP, which will enable more gas to flow from the north into the southern states.
  - Infrastructure providers are seeking opportunities to work with producers to bring gas to market through the construction of new pipelines, the development of which will be contingent on producers proceeding with their projects.
  - Some infrastructure providers are looking at opportunities to reduce the financial barriers that upstream infrastructure can pose for junior producers, by entering into arrangements to develop processing and other upstream facilities.

- The ACCC supports governments continuing their work facilitating the timely and efficient development of new supply and infrastructure.

2.2. Introduction

This chapter provides an overview of the new sources of supply and infrastructure that could potentially be brought online to improve supply adequacy over the period 2022 to 2026, and beyond. The 2022-2026 period is the period over which potential shortfalls in supply from 2P reserves could emerge, with shortfalls expected to occur as early as 2022 in the southern states and by 2028 in Queensland. Across the east coast as a whole, a shortfall is expected to emerge in 2026.
As noted in chapter 1, supply from more speculative domestic sources (i.e. possible reserves, contingent or prospective resources) and/or LNG import terminals will be required to alleviate the projected shortfalls in supply. It may also be necessary to divert some gas that would otherwise be exported as LNG into the domestic market, if new supply sources cannot be developed rapidly enough. Additional transportation and storage infrastructure will also be required to enable gas to be transported where it is needed to alleviate shortfalls.

Figure 2.1 shows the location of the larger potential sources of new supply and infrastructure that have been identified by suppliers and infrastructure providers.\(^{33}\)
Figure 2.1: Location of larger potential new sources of supply
The information in this chapter is predominantly based on information obtained from producers, LNG import proponents and infrastructure providers using our compulsory information gathering powers and was current as at August 2021. The ACCC has not sought to independently test the validity of any of the information provided. Some care should therefore be taken when considering the projects discussed in this chapter, particularly given the inherent degree of uncertainty surrounding the development of new sources of supply and investment decisions.

## 2021 National Gas Infrastructure Plan

On 26 November 2021, the Department of Industry, Science, Energy and Resources released the first National Gas Infrastructure Plan (NGIP), following on from the Interim NGIP released in May 2021. The Interim NGIP identified the critical infrastructure priorities that could be brought online before 2027 to address the risks of daily and annual shortfalls.

The 2021 NGIP takes a longer-term view of development out to 2041 and identifies five priority actions to support efficient infrastructure development and avoid supply shortfall risks:

### 1. Expand storage and flexible supply capacity close to southern demand centres

Priority projects include those already identified in the Interim NGIP:

- Development of the Golden Beach gas storage project, offshore in Gippsland, Victoria
- Expansion of the Iona storage facility, near Port Campbell, Victoria
- Expansion of the South West Pipeline (SWP) in Victoria, which connects Port Campbell to the rest of the Victorian Transmission System (VTS)
- Construction of an import terminal, with Port Kembla Gas Terminal (PKG) identified as the most advanced project.

### 2. Prioritise proving the viability of new upstream resources

Supply from both existing southern and northern basins is set to decline during the remainder of this decade, leading to shortages in the longer term. This means new basin supply must be developed by the end of this decade.

Key commercial decision points for supply:

- By late 2022: Determine what combination of new basins in the north will create sufficient supply once most southern supplies are depleted.
- By early 2025: Identify the new northern basins to be scaled up based on commercial conditions.
- By mid-2027: Evaluate the role expanded north-south flows can play in placing downward pressure on domestic gas prices.

Currently, market modelling based on cost estimates has identified the optimum timing for new sources of supply, including:

- Gunnedah basin production (Narrabri Gas Project), online from 2026.
- Beetaloo basin production, online from 2025 and expanded in 2028.
- Galilee and/or North Bowen basin production, online by 2028 but may be earlier,
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depending on upstream exploration and appraisal and outcomes of pipeline pre-feasibility assessments.

Ongoing work to prove the viability of new fields in existing southern offshore basins is also vital. Where Moratoria and other regulatory restrictions on unconventional gas developments have restricted supply, there are opportunities for state and territory governments to help unlock further supply.

3. Advance early-stage infrastructure design and development activities that enable access to new basins

Industry and governments should advance mid-stream shared infrastructure planning to reduce delivery timeframes, while deferring commitments to major capital expenditure until the commercial viability of new basins is proven.

4. Enable increased north-south flows

In addition to those already proposed, expansions to the South West Queensland Pipeline (SWQP), Moomba to Sydney Pipeline (MSP) and Victorian Northern Interconnect (VNI) will be required by 2028 as supply is increasingly drawn from northern fields and requires transportation to southern demand centres.

Implementation of already announced plans for a staged expansion of the MSP and SWQP should proceed and industry should continue to evaluate the need for additional expansion over the longer-term to avoid future constraints.

5. Coordinate gas infrastructure priorities with the National Hydrogen Infrastructure Assessment

The Government will integrate planning for gas infrastructure with potential hydrogen industry growth in the next NGIP, due for release in late 2022.

Infrastructure development pathway

In addition to the five priority actions listed above, the NGIP sets out an infrastructure development pathway to connect the Gunnedah (Narrabri), Beetaloo, Galilee and North Bowen basins to the east coast gas market. The development pathway has been sequenced to help ensure the infrastructure is developed at the lowest cost.

These works will need to be completed and commissioned in advance of basin production start dates. Many of these proposed pipelines listed align with proposed projects from pipeline operators, which we have outlined in section 2.5.1 and in our January 2021 interim report.

Future

A further NGIP is planned for release in late 2022. It will provide updates on:

- supply and infrastructure pathways based on market developments
- new analysis of the implications and opportunities linked to clean hydrogen industry development
- the impact of further expansions to key north-south pipeline routes.
2.3. The timing for new domestic supply sources has been delayed in some cases, which has contributed to forecast shortfalls

Using the information provided by producers, we have identified those domestic gas supply projects that have either:

- been approved for development that could be brought online between 2022 and 2026, or
- not yet been approved for development, but which could potentially be brought online between 2022 and 2026.

We note that the supply of gas from each project’s 2P reserves has already been included in the calculation of the supply shortfalls in chapter 1. These projects will therefore only help address the projected shortfalls in supply, or the timing of the projected shortfalls, if production from 2P reserves is higher than what producers currently expect. This could occur if:

- higher levels of annual production are achieved from 2P reserves, or from the development of possible reserves, contingent or prospective resources
- projects are brought on earlier than expected
- other projects that have not yet been identified are brought into production.

2.3.1. A number of new domestic sources of supply already approved for development could be brought online by 2027

Table 2.1 sets out the domestic supply projects that are not yet in production but which producers have approved for development and are expected to come online by 2027. The table sets out producers’ estimates of:

- 2P reserves, possible reserves and contingent resources (2C) for each project
- forecast annual production for each project
- when supply from the project could commence and the key risks to the that timing.

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34 This table does not include projects such as Senex Energy’s Atlas Stage 2, which are already in production. This project is expected to supply an additional 6 PJ per year to the east coast gas market. Senex Energy, ‘Senex announces FID for Atlas expansion project’ (ASX announcement), 17 August 2021, https://www.senexenergy.com.au/wp-content/uploads/2021/08/2249153.pdf.
## Table 2.1: Projects approved for development to come online by 2027

<table>
<thead>
<tr>
<th>Operator</th>
<th>Project</th>
<th>Basin</th>
<th>2P reserves (PJ)a</th>
<th>Possible reserves (PJ)a</th>
<th>2C resources (PJ)a</th>
<th>Annual production (PJ p.a.)</th>
<th>Potential timing for supply</th>
<th>Key risks to timingb</th>
</tr>
</thead>
<tbody>
<tr>
<td>APLNG</td>
<td>Murrungama Surat</td>
<td>80</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>7.0</td>
<td>2022</td>
<td>T&amp;D</td>
</tr>
<tr>
<td>QGC</td>
<td>Goog-a- Bingo35</td>
<td>Surat</td>
<td>6</td>
<td>3</td>
<td>42</td>
<td>0.4</td>
<td>2022</td>
<td>JV &amp; I</td>
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<td>Denison</td>
<td>Denison South Bowen</td>
<td>7</td>
<td>3</td>
<td>4</td>
<td>-</td>
<td>0.5</td>
<td>2022</td>
<td>C, G</td>
</tr>
<tr>
<td>Denison</td>
<td>Denison North Bowen</td>
<td>2</td>
<td>1</td>
<td>4</td>
<td>0.2</td>
<td>2023</td>
<td></td>
<td>G, T&amp;D</td>
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<tr>
<td>Arrow</td>
<td>Red Hill Central Nth</td>
<td>27</td>
<td>0</td>
<td>487</td>
<td>0.6</td>
<td>2023</td>
<td></td>
<td>I &amp; JV</td>
</tr>
<tr>
<td>Arrow</td>
<td>Surat Gas Project (SGP) Tranche 3c</td>
<td>Surat</td>
<td>994</td>
<td>17</td>
<td>-</td>
<td>1.6</td>
<td>2024-26</td>
<td>I, JV, L &amp; R</td>
</tr>
<tr>
<td>SGP Tranche 1c</td>
<td>Surat</td>
<td>591</td>
<td>15</td>
<td>-</td>
<td>-</td>
<td>2.0</td>
<td>2024</td>
<td>L</td>
</tr>
</tbody>
</table>

Source: The information in this table is based on information provided by producers and current as at 31 August 2021. In most cases the information reflects information provided by the project operator, unless this was unavailable, in which case it is based on information provided by other producers in the joint venture.

Notes:  

a. 2P reserves, possible reserves and 2C resources are measured as at 30 June 2021.  

b. The classification criteria used for risks are: C for commercial factors, E&A for exploration and appraisal, F for financing, G for geologic factors, I for infrastructure access, including pipeline, processing and compression on a third party access and owner-operated basis, JV for joint venture agreement, L for land access, M for macroeconomic factors including international gas and oil prices, R for regulatory approvals (including environmental approvals), T&D for timing and delays, W for weather.  

c. Goog-a-Binge encompasses a drilling program across a number of QGC's fields. Figures in the table are for PLs 1009 and 1010 that will be brought online as part of this project. SGP Tranche 3 includes Hopeland and Wyalla, SGP Tranche 1 refers to Carn Brea. Supply from Carn Brea and Wyalla is intended to supplement production from Arrow's other fields that feed into the Daandine and Tipton central processing facilities. The timing of Carn Brea and Wyalla is therefore dependent on the performance of those other fields.  

As this table reveals, there are currently only seven projects that have been approved for development that could be brought online by 2027, the majority of which are very small with forecast production expected to be less than or equal to 2 PJ per annum. The one exception to this is APLNG's Murrungama field, which is forecast to produce 7 PJ per annum. This field, which is subject to an Australian domestic manufacturing supply condition,36 is expected to commence supply in 2022, having only been awarded by the Queensland government in 2020.37  

All the projects that have been approved for development are located in Queensland. They will not therefore directly address the projected shortfall in the south, but they could help to alleviate the shortfall if some of the gas is transported south via the SWQP and MSP, which APA is currently expanding (see section 2.5.2). We note that QGC controls supply from three of the seven projects (i.e. QGC's Goog-a-Binge project and Arrow's Surat Gas Project (SGP)).38 There is a risk therefore that gas from these projects could be exported, rather than alleviate the projected shortfall in the south (see section 4.6 for our assessment of the LNG producer's compliance with the Heads of Agreement).  

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35 Goog-a-Binge was reported as Myrtle and Ridgewood in our January 2021 interim report.  
37 Ibid.  
Possible reserves and contingent resources associated with the projects are, with one exception, relatively small. The exception is Arrow’s Red Hill Central project in the northern Bowen Basin, which is not connected to the east coast market. Any additional supply from all but Arrow’s project is therefore unlikely to have a material effect on projected shortfalls.

At this stage, most projects are expected to come online in 2022 or 2023. There are, however, some risks surrounding this timing. This can be seen in the delays that:

- Arrow has reported for the Red Hill Central and SGP Tranche 3 projects, both of which are expected to come online two to three years later than was forecast last year.39
- Denison Gas has reported for the Denison North and Denison South projects, which are expected to come online 6-12 months later than was forecast last year.40 Denison Gas has also revised down its forecast production from these projects (from 2.8 PJ p.a. to 0.7 PJ p.a.) over the last year.41

The delays and reductions in forecast production experienced by Arrow and Denison Gas highlight the challenges producers can face in bringing gas to market even when a project has been approved for development. While supply from these four projects is expected to be relatively small, the revisions have contributed to the projected shortfalls and the timing of those shortfalls (see chapter 1).

While not shown in table 2.1, the development of most of these projects will require new wells and upstream gathering systems to be developed. Some of these projects also require access to processing facilities controlled by another producer or joint venture partners, which can constitute a risk for the project. This risk was identified by:

- QGC for the Goog-a-binge project,42 which both require access to gas and water processing infrastructure jointly owned by QCLNG and APLNG. The development of these projects is therefore contingent on APLNG’s approval.43
- Arrow for the Red Hill Central project, which requires access to the processing facilities jointly owned by AGL and Arrow. The development of this wholly owned Arrow project is therefore contingent on AGL’s approval.

The risk posed by joint venture parties delaying projects has been identified by a number of producers over the course of the Inquiry. We will examine this issue further in Stage 2 of our review of the behavioural factors affecting upstream competition and the timeliness of supply (see chapter 3).44

Some other key risks to the timing of supply that producers have identified include geological factors, the commerciality of the project, environmental approvals and land access agreements. The barriers posed by these factors are discussed further in chapter 3.

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39 ACCC, Gas Inquiry 2017-2025 interim report, January 2021, Table 2.1.
40 ACCC, Gas Inquiry 2017-2025 interim report, January 2021, Table 2.1.
41 Ibid.
42 Goog-a-Binge encompasses a drilling program across a number of QGC’s fields. This risk only affects PLs 1009 and 1010 that will be brought online as part of this project.
43 Arrow also identified that access to processing infrastructure jointly owned by QCLNG and APLNG partially affects the SGP Tranche 3 project.
2.3.2. A large number of other domestic sources of supply could potentially come online but are yet to be sanctioned

Table 2.2 sets out the domestic supply projects that have not yet been approved for development but could potentially come online by 2027. This table does not include all the proposed projects in the Galilee or north Bowen basins, because either supply is not expected until after 2027, or the timing of supply is unknown.
Table 2.2: Domestic projects not yet sanctioned that producers identify could potentially commence supply by 2027

<table>
<thead>
<tr>
<th>Operator</th>
<th>Project</th>
<th>2P reserves (PJ)</th>
<th>Possible reserves (PJ)</th>
<th>2C resources (PJ)</th>
<th>Annual production (PJ p.a.)</th>
<th>Potential FID</th>
<th>Potential timing for supply</th>
<th>Key risks to timing of supply</th>
<th>Transmission pipeline investment to connect processing to market</th>
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<td><strong>Bowen Basin</strong></td>
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<td>20</td>
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<td>2022</td>
<td>C &amp; JV</td>
<td>Incremental</td>
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<tr>
<td></td>
<td>Mahalo</td>
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<td>100</td>
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<td>2.2-24.0</td>
<td>2022-23</td>
<td>2023-25</td>
<td>JV &amp; R</td>
<td>Incremental</td>
</tr>
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<td>1.0</td>
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<td>2023</td>
<td>E&amp;A, I &amp; L</td>
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<td>Blue</td>
<td>North Bowen</td>
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<td>227</td>
<td>1,055</td>
<td>47.5</td>
<td>2023-24</td>
<td>2024-25</td>
<td>I</td>
<td>New pipeline MOU with APA</td>
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<td><strong>Surat Basin</strong></td>
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<td></td>
<td></td>
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<tr>
<td>Central</td>
<td>Range</td>
<td>-</td>
<td>-</td>
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<td>15</td>
<td>2021</td>
<td>2023</td>
<td>T&amp;D</td>
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<td>Armour</td>
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<td>17</td>
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<td>2022-24</td>
<td>E&amp;A</td>
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<td>QGC</td>
<td>Suspend-Redrill &amp; SW2.6</td>
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<td>-</td>
<td>32</td>
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<td>2023-25</td>
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<td>GLNG</td>
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<td>-</td>
<td>205</td>
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<td>≥ 2022</td>
<td>2026-36</td>
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<td>Waldegrave</td>
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<td>1</td>
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<td>2023-24</td>
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<td>2025</td>
<td>I &amp; M</td>
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<td>30.0</td>
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<td>2026</td>
<td>I &amp; M</td>
<td>Existing pipeline</td>
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<td><strong>Galilee Basin</strong></td>
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<td>Galilee</td>
<td>Glenaras</td>
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<td>-</td>
<td>2,507</td>
<td>≤ 73</td>
<td>NA</td>
<td>2024</td>
<td>C &amp; I</td>
<td>New pipeline MOU with Jemena</td>
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</tbody>
</table>

Gas Inquiry 2017–2025
<table>
<thead>
<tr>
<th>Operator</th>
<th>Project</th>
<th>2P reserves (PJ)(^a)</th>
<th>Possible reserves (PJ)(^a)</th>
<th>2C resources (PJ)(^a)</th>
<th>Annual production (PJ p.a.)</th>
<th>Potential FID</th>
<th>Potential timing of supply</th>
<th>Key risks to timing of supply</th>
<th>Transmission pipeline investment to connect processing to market</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cooper Basin</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vintage</td>
<td>Vali</td>
<td>30</td>
<td>49</td>
<td>-</td>
<td>1.6</td>
<td>2021</td>
<td>2022</td>
<td>C, F, I &amp; JV</td>
<td>Existing pipeline</td>
</tr>
<tr>
<td>Pure Hydrogen</td>
<td>Windorah</td>
<td>-</td>
<td>-</td>
<td>347</td>
<td>7.3</td>
<td>2024</td>
<td>2025</td>
<td>F</td>
<td>Existing pipeline</td>
</tr>
<tr>
<td><strong>Bass, Gippsland and Otway basins</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GB Energy</td>
<td>Golden Beach</td>
<td>-</td>
<td>-</td>
<td>69</td>
<td>36.5 (two years only)</td>
<td>2021</td>
<td>2023</td>
<td>F</td>
<td>Existing pipeline</td>
</tr>
<tr>
<td>Beach</td>
<td>Enterprise</td>
<td>160</td>
<td>42</td>
<td>-</td>
<td>4.0</td>
<td>2022</td>
<td>2023</td>
<td>W</td>
<td>Existing pipeline</td>
</tr>
<tr>
<td>SGH</td>
<td>Longtom</td>
<td>-</td>
<td>-</td>
<td>206</td>
<td>16.7</td>
<td>2022</td>
<td>2023</td>
<td>I</td>
<td>Existing pipeline</td>
</tr>
<tr>
<td>Cooper</td>
<td>Annie</td>
<td>-</td>
<td>-</td>
<td>55</td>
<td>2.7-13</td>
<td>2022</td>
<td>2024-25</td>
<td>C &amp; JV</td>
<td>Incremental</td>
</tr>
<tr>
<td>Cooper</td>
<td>Manta</td>
<td>-</td>
<td>-</td>
<td>121</td>
<td>24.0</td>
<td>2024</td>
<td>2026</td>
<td>C &amp; I</td>
<td>Incremental</td>
</tr>
<tr>
<td>Esso</td>
<td>North Turrum</td>
<td>-</td>
<td>-</td>
<td>96</td>
<td>5-10</td>
<td>2024-25</td>
<td>2026</td>
<td>C, I &amp; E&amp;A</td>
<td>Incremental</td>
</tr>
<tr>
<td><strong>Gunnedah Basin</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Santos</td>
<td>Narrabri(^x)</td>
<td>13</td>
<td>-</td>
<td>1,798</td>
<td>20-25</td>
<td>≥ 2022</td>
<td>2026</td>
<td>I, E&amp;A &amp; R</td>
<td>New pipeline Development agreement with APA &amp; Hunter Gas Proposal</td>
</tr>
</tbody>
</table>

Source: This table is based on information provided by producers and current as at 31 August 2021. The information has not been independently verified by the ACCC. In most cases the information reflects information provided by the project operator, unless this was unavailable, where it is based on information provided by other producers in the joint venture. Because this table is largely based on information provided by the operators, there may be some differences between this table and the reserves and resources estimates in Appendix A, which is based on individual producer information.

Notes: a. 2P reserves, possible reserves and 2C resources are measured as at 30 June 2021.

b. The classification criteria used for risks are: C for commercial factors, E&A for exploration and appraisal, F for financing, G for geologic factors, I for infrastructure access, including pipeline, processing and compression on a third party access and owner-operated basis, JV for joint venture agreement, L for land access, M for macroeconomic factors including international gas and oil prices, R for regulatory approvals (including environmental approvals), T&D for timing and delays, W for weather.

c. The requirements to connect the gas field with the transmission pipeline network. Incremental is used to refer to those cases where a field is situated close to existing pipelines (e.g., < 50 km distance).

e. Narrabri includes all 2P reserves and 2C resources associated with the Gunnedah Basin.
Table 2.2 shows there are a large number of projects that could potentially be brought online by 2027, most of which are located in Queensland. There are also a reasonable number in the south. Close to a third of these projects are being undertaken by the LNG producers, or Arrow as part of the SGP (which QGC has first rights to the gas produced).\textsuperscript{45}

The development of any of these projects could help to alleviate the projected shortfalls in supply, as some of the projects have large volumes of contingent resources and possible reserves. However, while there are a large number of projects, just under half have no 2P reserves and are therefore quite speculative in nature.

There is some risk surrounding the timings assumed for both FID and the commencement of supply. Before a decision is made to develop these projects, the relevant producer will need to establish that the projects are commercial to develop, obtain the relevant regulatory approvals and make a FID to proceed with the development. Most of the producers have indicated that a significant amount of exploration and appraisal activity will need to be undertaken before a FID can be made and work can commence on developing the infrastructure (i.e. processing facilities and pipelines) required to bring the gas to market. There is also a risk some projects will not be developed at all.

Other commonly cited risks that producers note may affect either the decision to develop the project or the timing of the development include the commercial viability of the project, access to infrastructure, regulatory approvals (including environmental approvals and land access) and, for junior producers, access to financing. Compared to our January 2021 interim report, exploration and appraisal (E&A) risk is less prevalent, while commercial, financial and macroeconomic factors (including oil and gas prices) are now more prevalent. A number of producers have also identified decisions by joint venture parties as a risk to the timing of supply. As noted in section 3.1, we intend to investigate this further in Stage 2 of our review of upstream competition and the timeliness of supply.

**While supply from most projects is expected to be less than 10 PJ per annum, there are some larger potential projects**

The majority of projects listed in table 2.2 are expected to supply less than 10 PJ per annum. The notable exceptions to this in the southern states are:

- SGH’s Longtom project, which could produce 16.7 PJ per annum and is targeting FID in 2022, with supply potentially commencing in 2023
- Lakes Blue Energy’s (previously Lakes Oil) Wombat project, which could produce 20 PJ per annum and is targeting FID in 2022, with supply potentially commencing in 2023
- Beach’s Trefoil project, which could produce 25 PJ per annum and is targeting FID in 2024, with supply potentially commencing in 2025
- Cooper’s Manta project, which could produce 24 PJ per annum and is targeting FID in 2024, with supply potentially commencing in 2026
- Santos’ Narrabri project, which could produce 20-25 PJ per annum and is targeting FID post 2022, with supply potentially commencing in 2026.\textsuperscript{46}

In the north, there are six projects that could potentially supply more than 10 PJ per annum. These include:

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\textsuperscript{46} The Golden Beach project is also expected to produce material volumes, but this is only expected to occur for two years before it transitions to providing gas storage services.
• Central’s Range project in the Surat Basin, which could produce 15 PJ per annum and is targeting FID in 2021, with supply potentially commencing in 2023.

• Galilee Energy’s Glenaras project in the Galilee Basin, which could produce up to 73 PJ per annum, with supply potentially commencing in 2024.47

• Blue Energy’s Sapphire project in the north Bowen Basin, which could produce 30 PJ per annum and is targeting FID in 2023, with supply potentially commencing in 2024

• Comet Ridge and Santos’s Mahalo project in the Bowen Basin, which could produce up to 24 PJ per annum and is targeting FID in 2022-23, with supply potentially commencing between 2023 and 2025.48

• APLNG’s Ironbark project in the Surat Basin, which could produce 26 PJ per annum and is targeting FID in 2024, with supply potentially commencing in 2025

• APLNG’s Ramyard project in the Surat Basin, which could produce 30 PJ per annum and is targeting FID in 2025, with supply potentially commencing in 2026.

For a number of these larger projects access to infrastructure is a key risk. The Glenaras, Sapphire and Narrabri projects, for example, require significant investment in processing, pipeline and other associated infrastructure to connect the Galilee, north Bowen and Gunnedah basins to the east coast gas market (see section 2.5.1). A large number of the other projects listed above, will also either require third party access to existing processing facilities or significant investment in new processing facilities and other upstream infrastructure.

**The potential timing of supply from a large number of the projects has been delayed, contributing to projected supply shortfalls**

Since we reported in January 2021, the majority of projects have had the timing of their FID and/or supply delayed. The sole exception is APLNG’s Towrie field in the Bowen Basin, which has had the timing of both FID and supply brought forward.

Some projects we reported in January 2021 have been delayed beyond 2027 and so have not been included in table 2.2. These include Beach’s La Bella project APLNG’s Kainama and Woleebee projects, and some fields in Denison’s Denison North and South projects.

The delays observed in the south have contributed to the acceleration of the shortfall in the southern states from 2024 to 2022. When compared to what was reported last year, the potential timing of supply from most projects in the southern states has been delayed by one to two years, although there are some longer delays like Beach’s La Bella project, which has been pushed back from 2024 to an unspecified date.

The potential timing of supply from Santos’ Narrabri project has also been delayed by around two years. The delay stems from an appeal of the NSW Independent Planning Commission’s decision to allow the Narrabri project to proceed, which was dismissed by the NSW Land and Environment Court. In announcing the dismissal, Santos noted that the

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48 With Santos’ help Comet Ridge is in the process of purchasing APLNG’s share of the Mahalo Gas Project. In exchange, Santos has gained the right to increase their share of the project up to 50%, and to farm into Comet Ridge’s Mahalo North and East fields up to 50%. Additional appraisal work is being undertaken at Mahalo North ahead of finalising the project scope and development in conjunction with completing the acquisition of APLNG’s share of the Mahalo Project. See http://www.cometridge.com.au/wp/wp-content/uploads/2021/08/2021.08.03-COI-Funded-Acquisition-of-APLNGs-30-of-Mahalo-Gas-Project.pdf.
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appeal had caused a 12 month delay to drilling, with the project on hold during the course of the appeal.49

Beach’s Enterprise project, however, which has only recently been discovered and has 160 PJ of 2P reserves has been identified as potentially being brought online by 2023. While this is a positive sign, its inclusion is not enough to fully offset the effect of delays and exclusions on the long term east coast supply outlook.

In a similar manner to the south, a large number of projects in the north have also experienced delays, with some being delayed by up to five years. Most of the delays have been observed on APLNG’s projects, with supply from its Ramyard, Ironbark, Woleebee, Kainama, Dalwogan projects pushed back by two to five years.

2.4. The Port Kembla LNG import terminal appears to be proceeding but some uncertainty remains

In addition to the domestic supply projects outlined above, there are currently five proposals to develop LNG import terminals in the east coast gas market, all of which are located in the southern states. Table 2.3 provides an overview of these five proposals.

<p>| Table 2.3: Proposed LNG import terminals |</p>
<table>
<thead>
<tr>
<th>Operator</th>
<th>Location</th>
<th>Status</th>
<th>Annual supply (Daily maximum)a,b</th>
<th>Potential timing for FID</th>
<th>Potential timing for supply</th>
<th>Key risks to timing of FID and supplyc</th>
<th>Pipeline proposals</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>AIE</td>
<td>Port Kembla</td>
<td>Construction commenced on terminal</td>
<td>130-180 PJ p.a. (522 TJ/d)</td>
<td>FID reached for LNG terminal</td>
<td>Mid 2023</td>
<td>C</td>
</tr>
<tr>
<td></td>
<td>EPIK</td>
<td>Newcastle</td>
<td>FEED stage (pre-FID)</td>
<td>54.5-110 PJ p.a. (280 TJ/d)</td>
<td>Sep 2022</td>
<td>Jul 2025</td>
<td>R, C</td>
</tr>
<tr>
<td>Victoria</td>
<td>Viva</td>
<td>Geelong</td>
<td>FEED stage (pre-FID)</td>
<td>80-140 PJ p.a. (500-600 TJ/d)</td>
<td>Q3 2022</td>
<td>Q2 2024</td>
<td>R, C</td>
</tr>
<tr>
<td></td>
<td>Vopak</td>
<td>Avalon</td>
<td>Pre-FEED</td>
<td>139-200 PJ p.a. (400-800 TJ/d)</td>
<td>2024</td>
<td>2026</td>
<td>R, C, I</td>
</tr>
<tr>
<td>South Australia</td>
<td>Venice</td>
<td>Outer Harbour</td>
<td>FEED stage (pre-FID)</td>
<td>80-100 PJ p.a. (500 TJ/d)</td>
<td>Apr/May 2022</td>
<td>H1 2024</td>
<td>R, C</td>
</tr>
</tbody>
</table>

Source: The information in this table is based on information provided by LNG import terminal proponents and has not been independently verified by the ACCC.

Notes: a. Annual supply refers to the average annual quantity of gas that could be supplied and is measured on a PJ per annum basis. Daily maximum refers to the maximum quantity of gas that could be injected into a pipeline on a firm basis and is measured on a TJ/day basis.

b. All proposed LNG storage and regasification terminals propose to use a floating storage and regasification unit (FSRU) that can receive and store between 3.2 and 4.2 PJ of LNG (depending on the energy content of the cargo).

c. The classification criteria used for risks are as follows: C means commercial factors (including access to capital), I refers to infrastructure access (e.g. access to pipelines), R refers to regulatory barriers.

We do not expect all of these projects will be developed as the combined capacity of the five projects exceeds the total domestic demand in the east coast.

The potential timing of supply has also been delayed by between six months and two years across the various projects. This highlights some of the risks and uncertainty surrounding these projects. The key risks that the LNG import proponents have noted they are facing are:

- the regulatory approvals processes
- commercial factors, such as finding customers that are willing to enter into contracts to underwrite the development.

Of the five projects set out in table 2.3, AIE’s Port Kembla terminal is the most advanced, with AIE having made the investment decision to proceed with the construction of the LNG terminal. This work commenced in March 2021 and is expected to be completed by mid-2023. In November 2021, AIE announced that it had signed a charter agreement with Höegh to supply the first Floating Storage and Regasification Unit (FSRU) to operate at Port Kembla. Höegh and AIE have also agreed to collaborate on the future design and development of a new generation FSRU capable of receiving clean fuels such as green hydrogen as well as natural gas.

In the last 12 months, Jemena has made a conditional FID to connect AIE’s Port Kembla LNG import terminal to the EGP through the development of a lateral pipeline, and convert the EGP to a bi-directional pipeline, which will allow gas to flow to Victoria from Port Kembla. On this, we understand although a GTA has not yet been executed, Jemena and AIE have previously executed a Project Development Agreement for the lateral, under which AIE have agreed to contract the full capacity of the lateral pipeline and intends to make this capacity available to customers of its LNG import terminal at Port Kembla.

AIE is currently expecting that supply from the LNG import terminal could commence from mid-2023, which is six months later than it forecast last year.

Of the remaining four proposals:

- Venice Energy’s proposed Outer Harbour terminal in Adelaide is in the Front End Engineering Design (FEED) stage and waiting on state government approvals. Venice has reportedly entered into a Heads of Agreement with GasLog for the supply of a FSRU. It has also initiated a study to assess the feasibility of reversing the flow of the PCA pipeline to bring gas into Victoria. Venice expects to make a FID in April or May 2022. If it decides to proceed with the terminal, Venice has indicated supply could commence in the first half of 2024, up to 18 months later than it previously forecast.

- Viva Energy’s proposed Geelong terminal, which would be co-located with the Corio oil refinery in Victoria, is also in the FEED stage. Viva expects to make a FID in the third quarter of 2022, with supply to potentially commence in the second quarter of 2024. The potential timing for supply has not changed from Viva’s previous forecast.

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50 AIE, ‘AIE and Höegh LNG sign deal to secure NSW and Victoria’s Energy Future’ (Media Release), 30 November 2021
51 See ACCC, Gas Inquiry 2017-2025 interim report, January 2021, Table 2.3.
53 Plan SA has recently released the designs for public consultation News story in The Advertiser 15/10/21.
55 Ibid.
56 Ibid.
57 ACCC, Gas Inquiry 2017-2025 interim report, January 2021, Table 2.3.
• EPIK’s proposed GasDock terminal in Newcastle is in the FEED stage, with a FID expected to be made in September 2022. If it decides to proceed with the terminal, EPIK has indicated supply could commence in mid-2025, two years later than it previously forecast.\(^{58}\)

• Vopak’s proposed Avalon terminal in Port Philip Bay was announced in March 2021. It is currently in the pre-FEED stage and expects to make a FID in 2024. If it proceeds, Vopak expects supply could commence in 2026.\(^{59}\)

The demise of the Crib Point LNG import project underscores the impact that the regulatory approvals process can have on the development of import terminals, with the project being abandoned following the Victorian Minister for Planning’s decision that the project would have unacceptable environment effects.\(^{60}\)

Of the projects identified in table 2.3, AIE’s Port Kembla project is the only one that has obtained all relevant regulatory approvals. While it has overcome this hurdle, AIE must still find customers that are willing to enter into the long term contracts required to justify calling the FSRU into Port. Until customers sign on to supply contracts, there is still a degree of risk surrounding the project. In this regard, it is worth noting that Viva has been trying to position its Geelong terminal as a better alternative to Port Kembla, because it would not require the same level of pipeline investment to bring the gas to Victoria. EnergyQuest has estimated that transportation could add $1/GJ to cost of LNG imported to Port Kembla supplied into Victoria.\(^{61}\)

2.5. There are positive signs for infrastructure investment, both in the short and longer term

2.5.1. Investment in pipelines to connect new sources of supply is contingent on producers deciding to proceed with the development

As noted in our January 2021 interim report, several prospective transmission pipeline projects have been announced in recent years that would connect to new supply sources and provide greater connectivity across the east coast. The projects identified in that report included:

• Jemena’s proposed Northern Growth Strategy, which would connect the Beetaloo sub-basin to the east coast via an expanded and extended Northern Gas Pipeline (NGP), continuing via the Galilee basin to the Queensland Gas Pipeline (QGP)

• AGIG’s proposed Amadeus to Moomba Gas Pipeline (AMGP), which would connect the Amadeus Basin to Moomba and allow gas from the Mereenie Stairway development to be supplied into the east coast\(^{62}\)

• APA’s proposed Galilee to Moranbah Pipeline (GMP) and Moranbah to Wallumbilla/Gladstone Pipeline, which would connect the Galilee and north Bowen basins with the east coast market

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\(^{58}\) Ibid.

\(^{59}\) Ibid.

\(^{60}\) AGL’s decision followed the Victorian Minister for Planning’s decision that the project would have unacceptable environment effects, https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/crib-point.


\(^{62}\) Central Petroleum has indicated that their Mereenie Stairway development is intended to underwrite the construction of the AMGP. This development represents additional infill drilling for the Mereenie field and so has not been included in either tables 2.1 or 2.2.
• APA’s proposed Western Slopes Pipeline (WSP), which would connect the Narrabri gas field to the MSP

• The proposed Hunter Gas Pipeline (HGP), which would connect Wallumbilla to the Hunter Valley via Narrabri.

Based on pipeline operators’ board documents, it appears little progress has been made on any of these projects since July 2020, and it is likely to be some time before any decisions are to be made on the development of these pipelines. This is because most of these projects are contingent on FIDs being made by producers to bring on new supply sources, to which the pipelines would connect (see table 2.2). For example, Santos is yet to make a FID on proceeding with the development of Narrabri, so little can be done to progress either the WSP or the HGP. Similarly, FIDs are yet to be made for the development of supply from the Beetaloo sub-basin, Galilee and north Bowen basins, because they are each at a very early pre-feasibility stage.

One new development that has occurred over the last 12 months is that Empire Energy announced it has entered into a memorandum of understanding (MOU) to:

...explore opportunities...for APA to build, own and operate gathering, production, processing and transportation infrastructure for the movement of gas and liquids from Empire’s Northern Territory assets.\(^{63}\)

As part of this announcement, APA outlined its Northern and Eastern strategies, which would involve an expansion of the Amadeus Gas Pipeline (AGP) between the Beetaloo sub-basin and Darwin, as well as a greenfield pipeline connecting the AGP and the Carpentaria Gas Pipeline (CGP). The proposed greenfield pipeline would effectively duplicate Jemena’s NGP.

As outlined in our January 2021 interim report, we have some concerns about the priority that Jemena and APA appear to have accorded to connecting new pipelines to their existing pipelines, because it could result in the unnecessary duplication of pipelines. It may also result in the size and/or pipeline route that is developed not reflecting all the potential demand in an area. This form of inefficient investment could adversely affect the commercial viability of developing some of the resources in a region and, as are result, limit the volume of gas supplied from these areas. It could also adversely affect end users of gas if higher transportation charges are passed on.

The ACCC therefore encourages state and territory governments to:

• facilitate a more coordinated approach to the planning of pipelines required to bring new sources of supply to market, where feasible

• encourage these pipelines to be developed through a competitive process and operated on a third party access basis.

The Commonwealth government’s NGIP and Basin Development Plans and the Queensland government’s Bowen Basin pipeline study may help to facilitate a more coordinated approach.

2.5.2. Transportation upgrades to bring more gas to the southern states are proceeding

Over the last 12 months, a number of pipeline operators have commenced work on expanding the capacity of existing transmission pipelines.

\(^{63}\) Empire Energy, ‘MOU Executed with APA Group’, 27 October 2021, https://app.sharelinktechnologies.com/announcement/asx/fbe2273f91e0c483a0e937ed28515051
APA, for example, announced in May 2021 that it had made a FID to proceed with a 25% expansion of the SWQP and MSP. Stage 1 of this expansion will involve the installation of compressor stations on the SWQP and MSP, which will expand the capacity by around 12%. This expansion is principally being underwritten by Origin, which signed a new GTA starting on 1 January 2023.\footnote{APA, 'Gas-Fired Recovery: Infrastructure and Investment Consultation Note', 2 August 2021, \url{https://www.apa.com.au/globalassets/submissions/2021/apa-response-to-ngip-and-investment-framework-consultation-note-aug-2021.pdf}, Page 6.} Stage 2 of the expansion will involve the installation of additional compression, which will further expand capacity by 13%. According to APA, the stage 2 expansion will be staged to meet customer demand but is currently targeted for commissioning towards the end of 2023.\footnote{AFR, 'APA heads off gas shortage with $270m grid expansion', 5 May 2021, \url{https://www.afr.com/companies/energy/apa-heads-off-gas-shortage-with-270m-grid-expansion-20210505-p57p4}.} APA has also undertaken preliminary design works on a potential stage 3 expansion that would add a further 25% of capacity to the MSP and SWQP.

In the last 12 months, Jemena has also made a conditional FID to:

- connect the Port Kembla import terminal to the EGP through the development of a lateral pipeline
- convert the EGP to a bi-directional pipeline, which will allow gas to flow to Victoria from Port Kembla.

APA’s Western Outer Ring Main (WORM) project in the Victorian Transmission System (VTS) along the outskirts of Melbourne has been approved, with an Environmental Effects Statement (EES) and pipeline licence application submitted. It is expected this will be completed in the second quarter of 2023.

While there has been investment in upgrading existing pipelines, there may be some constraints yet to be addressed, such as the South West Pipeline in Victoria. This is one of the priority projects identified in the 2021 NGIP and would enable more gas to flow from the Iona gas storage facility and new Otway basin fields into Victoria.

### 2.5.3. Pipeline operators are trying to expand vertically, and this may help junior producers

In addition to the pipeline investments outlined above, pipeline operators have started to invest in upstream infrastructure. APA, for example, owns and operates the Orbost gas processing plant, while Jemena owns and operates the Atlas and Roma North gas processing plants.

Both APA and Jemena are continuing to actively investigate opportunities in this area. Some recent examples include:

• APA entering into an MOU with Empire Energy (see section 1.4.1), which provides for the parties to ‘explore opportunities…for APA to build, own and operate gathering, production, processing, and transportation infrastructure’.

As discussed in January 2021, this is a positive development that could help to reduce barriers to entry faced by junior producers and facilitate more competition amongst suppliers over the longer term. There is, however, some risk that this form of vertical integration by pipeline operators may have an adverse effect on upstream competition, because it may result in pipeline operators conferring an unfair advantage on their affiliated upstream assets. This is expected to be addressed in the ring fencing provisions in the new gas pipeline regulation reforms, which will now apply to pipelines subject to both the lighter and stronger forms of regulation. These provisions are designed to ensure separation of pipeline operations from associated businesses in other markets.

2.5.4. Investment in storage capacity is proceeding in the south

Over the last 12 months, Lochard Energy and GB Energy have progressed with their respective developments of additional storage capacity in Victoria.

Lochard Energy, for example, decided in November 2020 to proceed with the phase 4 expansion of the Iona storage facility, which will expand the capacity up to 570 TJ per day. The project is expected to be completed by the second quarter of 2022, subject to operating regulatory approvals.

GB Energy’s Golden Breach Project has also progressed over the last 12 months. This project will involve the development of a new underground storage facility connected to the VicHub at Longford and is projected to have a storage capacity of 12.5 PJ (around half the capacity of the Iona underground facility).

While a FID is yet to be made, work is progressing on financing the FEED, with Jemena now expected to be GB Energy’s infrastructure partner. The Victorian Minister for Planning also announced in April 2021 that the project could proceed with acceptable environmental effects, subject to some project modifications. If a FID is made, approximately 43 PJ of gas will need to be produced from the Golden Beach gas field over a two year period before it could be used as a storage facility. GB Energy is currently expecting gas production to commence in 2024.

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69 This will enable gas supplied via the Longford processing facility, the EGP or the VTS to be injected into storage and gas withdrawn from storage to be injected into the EGP, VTS or TGP.

3. Review of upstream competition and timeliness of supply

3.1. Key Points

- The long-term outlook for the east coast gas market is critically dependent on the timely development of new sources of supply and a more competitive upstream market. We are reviewing the structural and behavioural factors that may be affecting the timeliness with which gas is brought to market and/or contributing to the lack of effective upstream competition.

- Stage 1 of this review has focused on the structural factors and is now complete. Our key findings are that:
  
  o Greater diversity and more timely supply could be encouraged through changes to government processes for releasing acreage and approving, monitoring and enforcing compliance with work programs.
  
  o Upstream competition and the timeliness of supply could be significantly improved by reducing the infrastructure, regulatory and capital barriers faced by producers. It could also be improved if owners of existing upstream infrastructure provided third party access to this infrastructure on reasonable terms.

- We recommend:
  
  o State, territory and Commonwealth governments:
    - not grant acreage to producers with substantial existing acreage unless satisfied it will not affect the timing of their development of existing or new acreage
    - follow Queensland’s lead and consider both the diversity of suppliers and the efficiency with which gas can be brought to market, alongside the technical and financial capabilities of tenderers
    - proactively encourage gas to be brought to market in a timely manner through the adoption of shorter timeframes, where appropriate, and greater oversight of work programs.
  
  o Steps be taken to reduce the infrastructure, capital and regulatory barriers faced by producers by:
    - considering the implementation of a third party access regime for upstream infrastructure (i.e. gathering pipelines, natural gas processing, water treatment and compression facilities) and storage facilities that, like the lighter form of regulation that applies to gas pipelines, would provide for recourse to a commercially-oriented dispute resolution mechanism if an access dispute arises
    - removing duplication in regulatory approvals processes (particularly between the Commonwealth and states/territories), addressing limitations and uncertainties in these processes and helping producers to navigate these processes.

- We also note the Commonwealth government’s efforts to help reduce the capital barriers faced by producers, by enabling market participants and financiers make more informed investment decisions and encouraging more market-driven investment through measures such as the Strategic Basin Plans and National Gas Infrastructure Plan.

- Stage 2 of our review will be undertaken in 2022 and focus on behavioural factors that may be affecting upstream competition and/or the timeliness of supply.

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71 The term ‘producers’ is used throughout this report to refer to entities currently producing gas and entities that are not currently producing but have an interest in gas reserves and/or resources.
3.2. Introduction

In the January 2020 and 2021 interim reports, we announced our intention to undertake a review of the factors that may be limiting competition in the upstream segment of the east coast gas market and/or affecting the timeliness with which gas is brought to market.

This review is in response to concerns raised throughout the Inquiry about the degree of concentration in this part of the market (see chart A.4 in Appendix A) and the structural and behavioural factors that may be impeding competition, or otherwise preventing gas from being supplied to market in a timely manner.72

The need for the review is reinforced by other aspects of the Inquiry that point to the limited degree of competition in this part of the market, as highlighted by:

- the pricing behaviour that we have observed over the course of the Inquiry and our review of suppliers' pricing strategies, which indicates competition is posing little constraint on producers' pricing decisions.73
- C&I user surveys we have undertaken, which have consistently raised concerns about the lack of effective upstream competition and the adverse effect this has on selling practices, gas prices and the non-price terms and conditions in GSAs.74

The review is being conducted in two stages:

- Stage 1 has focused on the structural factors that may be impeding competition or the timeliness of supply, such as government processes and the barriers faced by producers when developing tenements.
- Stage 2, which we are undertaking in 2022, will focus on behavioural factors that may impede competition or the timeliness of supply, such as joint venture arrangements, marketing arrangements, mergers and acquisitions, exclusivity provisions and producers' decisions about when to bring on supply.

To help inform the review, we have issued compulsory information notices to a sample of small and large producers. We have also held meetings with a number of producers and state, territory and Commonwealth government departments or agencies involved in the release of acreage and the granting of permits. In mid-September, as part of a public consultation process, we also published an issues paper and sought public submissions from interested parties on the structural and behavioural factors that may be affecting supply and/or upstream competition.75

In total, we received 18 responses to the issues paper. Submissions were received from:

- Users associations (the Energy Users Association of Australia (EUAA) and the Major Energy Users (MEU) group).
- Producers and associations (Australian Petroleum Production & Exploration Association (APPEA), APLNG, Arrow, CNOOC, Comet Ridge, Cooper Energy, ExxonMobil, GLNG, Origin, Santos, Senex, Shell, Tokyo Gas, Vintage Energy and WestSide).

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Based on the public submissions and feedback from stakeholders and the responses provided to the compulsory information notices, it would appear there are a number of structural factors impeding both upstream competition and the timeliness with which gas is brought to market. These factors, discussed below, relate to:

- the processes employed by governments when releasing acreage, granting permits, and monitoring and enforcing compliance with work programs
- the geological, infrastructure, commercial and regulatory barriers faced by producers.

While it has been suggested that some of these structural factors are intractable and an inherent feature of the gas market, we have identified several potential improvements that could be made to facilitate more effective upstream competition and the timely development of supply. A summary of our recommendations is set out in box 3.1 below.

**Box 3.1: Summary of recommendations to address structural factors**

**Improvements to government processes and practices**

Government processes related to the release of acreage, the grant of permits and the monitoring and enforcement of compliance with work programs appear to be contributing to the lack of diversity and the slower development of new sources of supply. To address these issues, we recommend that:

- when releasing acreage for exploration, governments:
  - not grant acreage to producers that already control significant acreage they can be satisfied that it won’t affect the producer’s development of existing or new acreage
  - follow Queensland’s lead and consider both the diversity of suppliers and the efficiency with which gas can be brought to market, alongside the technical and financial capabilities of tenderers
- governments actively encourage gas to be brought to market in a timely manner by:
  - specifying shorter timeframes for exploration, appraisal and production activities and refusing to renew exploration and/or retention permits for a second term where this is possible under legislation and where appropriate to do so
  - carefully considering producers’ proposed work programs and the assumed timeframes, regularly monitoring compliance with work programs and taking action for non-compliance (including by requiring permits to be relinquished) where appropriate.

**Reducing the structural barriers faced by producers**

Producers can face significant geological, infrastructure, commercial and regulatory barriers when developing their tenements, affecting both the number of producers that are able to compete and the timeliness with which gas is brought to market. While it is not possible to reduce all of these barriers, we recommend that steps be taken to reduce:

- infrastructure barriers by considering the implementation of an industry specific third party access regime for upstream infrastructure (i.e. gathering pipelines, natural gas processing, water treatment and compression facilities) and storage through the National Gas Law (NGL) and National Gas Rules (NGR) that, like the lighter handed form of regulation applying to gas pipelines, would provide for recourse to a commercially-oriented arbitration if a dispute arises
- regulatory barriers by:
  - streamlining and harmonising regulatory approvals processes across and between governments (particularly between the Commonwealth and states/territories).
  - removing other limitations and sources of uncertainty in regulatory processes
  - helping producers navigate these processes.
3.3. Government processes may be contributing to the lack of diversity and the slower development of new sources of supply

Governments play an important role in influencing the development of gas in the east coast gas market, with states and territories responsible for releasing acreage, granting permits to explore for, appraise and produce gas in tenements located onshore and within three nautical miles of the coast. For offshore areas beyond three nautical miles, Joint Authorities (consisting of the responsible Commonwealth minister and relevant state or territory minister) are responsible for these activities. In addition to these activities, state, territory and Commonwealth governments are responsible for approving, monitoring and enforcing compliance with work programs.

As discussed in further detail below, the processes used by governments when releasing acreage for exploration can directly affect the degree of diversity in this part of the market. The timeframes allowed for exploration, appraisal and production, and the processes used to approve, monitor and enforce compliance with work programs can also affect the timeliness with which gas is brought to market. We have therefore considered whether any changes could be made to these processes to facilitate more competition and/or more timely supply.

Importantly, we have not sought to undertake a detailed review of all the government processes. Rather, we have focused on those aspects of these processes that may be affecting diversity in the market and/or the timeliness of supply.

3.3.1. Greater diversity could be encouraged through changes to the processes used by governments to release acreage for exploration

The processes used by governments when releasing acreage for exploration determines which producers initially hold tenements. While the holdings of tenements can change over time through joint venture arrangements, mergers and/or acquisitions, the initial grant of exploration permits still has an important influence on the degree of diversity in this part of the market and competition over the medium to longer term.

The processes used and the matters considered by state, territory and Commonwealth governments when granting exploration permits currently differ in each jurisdiction. There are, however, some common features across the jurisdictions, with all jurisdictions conducting competitive processes and evaluating tenderers based on their proposed work program, financial capacity and technical expertise. A number of jurisdictions also consider the tenderer’s past compliance record.

In Queensland, tenderers can also be subject to special criteria. In recent tenders, these special criteria have included the ability of the tenderer to contribute to both a diverse and efficient petroleum and gas industry in Queensland.

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76 The term ‘tenement’ is used to refer to an area that is subject to a permit, authority, licence, lease, or any other instrument granted by a government that allows the holder to explore for, appraise or produce gas in that area.

77 In the east coast the only exception to this is Tasmania, which is the sole responsibility of the Commonwealth Minister.

78 The Joint Authorities are supported by the National Offshore Petroleum Titles Administrator (NOPTA), which is the technical advisor to the Joint Authority and responsible for providing information, assessments, analysis, reports, advice and recommendations to the Joint Authority. They are also supported by the National Offshore Petroleum Safety and Environment Management Authority (NOPSEMA), which is responsible for the regulation of occupational health and safety, structural integrity and environmental management.

79 In the last tender conducted in 2020, these two criteria were separately accorded a 15% weighting in the evaluation criteria. Queensland Government, Petroleum and Gas Bowen-Surat basins Tender: PLR2020-2, 2020.
Stakeholders generally supported the inclusion of the diversity and efficiency criteria

In our issues paper, stakeholders were asked for their views on whether governments should explicitly consider diversity and efficiency, or the potential impacts on competition when awarding acreage.

Most stakeholders viewed the inclusion of diversity and efficiency criteria favourably. Some producers did, however, note the need for greater transparency around how these criteria are to be evaluated and weighted.

A number of producers also noted the need for care to be taken to ensure that these criteria do not overshadow other factors, such as the technical and financial capability of the tenderer to develop acreage. Origin, for example, stated that:

...to the extent these criteria limit the ability for larger participants to compete for access to new tenures (despite their technical and financial capabilities), this could have implications for the cost and timeliness of resource developments.80

In contrast to these stakeholders, Santos stated that ‘it has not been proven that the diversity criteria improve competition in the market’ and added that it would be more appropriate to consider operator capability.81

ACCC observations and recommendations

The ACCC recommends that state, territory and Commonwealth governments consider:

- following Queensland’s lead by including the diversity and efficiency criteria in their evaluation processes
- discouraging larger producers from ‘warehousing’ gas, by not granting acreage to producers that already control significant volumes of undeveloped reserves and resources, unless satisfied that it will not affect the development of a producer’s existing holdings or the new acreage.

As stakeholders have observed, there are a number of factors that governments need to consider when releasing acreage. While technical and financial capability are among the more important, it is also relevant to consider, as Queensland has, the diversity of suppliers and the efficiency with which gas can be brought to market. The reasons for this are:

- Considering technical and financial capability alone, will not ensure that gas is brought to market in a timely manner. Rather, the application of these criteria could result in larger producers being awarded large amounts of exploration acreage and not developing it because they have a finite amount of resources, or because they do not want to place downward pressure on prices by increasing supply.
- There may be a need to decide between competing applications by producers, all of whom may have the requisite degree of technical and financial capability. In these circumstances, the application of the diversity and efficiency criteria should result in a better outcome for the market, than focusing on technical and financial capability alone.

It is important to note that the diversity and efficiency criteria may not always point in the same direction. For example, if a new entrant and larger producer were competing for

80 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5. Shell also noted that the application of the diversity criterion had in some cases resulted in acreage being awarded to organisations that subsequently transferred the acreage to other operators, or relinquished the acreage at the end of the work period without having undertaken any field activities.

Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 2-3.

81 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 4.
 acreage and the acreage was next to existing infrastructure owned by the larger producer then while the diversity criterion may point to the selection of the new entrant, the efficiency criterion may to the selection of the existing owner of the infrastructure if greater emphasis is placed on productive efficiency.

The term ‘may’ has been italicised because even if the acreage was located next to the larger producer’s existing facilities it may still be more efficient to grant it to the new entrant, particularly if the larger producer has a significant amount of existing acreage to develop, or if its existing infrastructure is fully utilised. Even if there was spare capacity in the large producer’s infrastructure, it may still be more efficient for the new entrant to develop the acreage, particularly if it can obtain third party access to the large producer’s upstream infrastructure. It may also be more efficient to grant it to the new entrant if consideration is given to the dynamic efficiency benefits.

As this discussion highlights, the application of these criteria and the direction in which they point will depend on the circumstances and in some cases there may be trade-offs between the two criteria that will need to be evaluated. While the inclusion of these criteria in the evaluation process may not simplify the relevant government’s task, it is an appropriate task for government to consider and assess the merits and trade-offs of the various criteria. Inclusion of these criteria can also be expected to result in more efficient outcomes than the application of technical and financial capability criteria alone.

Further support for their inclusion in the evaluation process, can be found by looking at Queensland’s experience in applying the two criteria. In short, the inclusion of these criteria alongside the technical and financial capability criteria, has coincided with a material increase in the amount of acreage being awarded to smaller producers in Queensland in the last three years, including Senex, Central Petroleum, Comet Ridge and Denison Gas. With supply from Senex’s Atlas project having already commenced and supply from Central Petroleum’s Range project expected to commence in 2023 (see table 2.2), this process is helping to foster the development of more upstream competition.

This is a positive development and highlights the potential for the processes used by governments at acreage release to encourage more diversity and a greater degree of competition between producers over the medium to longer term. That is, if these more junior producers reach a sufficient scale, then over the medium to longer term they should be able to compete more effectively with the larger LNG producers, who currently account for a significant proportion of reserves and resources, as well as uncontracted gas, which will benefit gas users.

The inclusion of explicit diversity and efficiency criteria in the evaluation process could also address the concerns raised in our prior reports about the potential for larger producers that already control significant volumes of undeveloped reserves and resources to be granted more acreage and to then ‘bank’ or ‘warehouse’ that gas.

3.3.2. Supply could be brought to market more rapidly through changes to exploration, appraisal and production timeframes

Beyond the initial release of acreage, there are a number of actions that governments can take in relation to exploration, appraisal and production permits that can affect the timeliness with which gas is brought to market, including the timeframes allowed for exploration, appraisal and production.

84 ACCC, Gas Inquiry 2017-2025 Interim report, January 2020, p. 43.
In some jurisdictions, the time allowed for exploration and appraisal activities and for production to commence is fixed by legislation. In others, the legislation sets out the maximum term allowed for such activities. In those jurisdictions where the legislation specifies a maximum term, governments have a greater degree of flexibility to issue permits for shorter periods of time if they consider gas could be brought to market more rapidly.

We understand that this approach has been used to varying extents in Queensland, with permits issued for shorter terms than those specified in legislation where the acreage was of a high quality. This has resulted in production from a number of projects commencing in a much shorter period of time than would otherwise be expected. Senex's Atlas project, for example, commenced production just over two years after being awarded the acreage in 2017.84 APLNG's Murrungama project is also expected to commence production within three years of being awarded the acreage in mid-2019 (see table 2.1).

Another option to encourage more timely supply that is available in some jurisdictions is to exercise the discretion governments have, to refuse to renew exploration and/or retention permits for a second term.

**Stakeholders largely supported governments taking a more proactive role**

In the issues paper, stakeholders were asked for their views on the options to bring gas to market more rapidly.

In most cases, stakeholders were supportive of the approach that has been employed in Queensland. A number of producers did, however, point out that it will usually take more time to develop marginal or frontier acreage and that this needed to be factored into any decision on exploration and development timeframes.85 Vintage, for example, noted that:

> As a rule, frontier acreage takes much longer to explore than acreage close to existing infrastructure. This is because, by definition, there has been very little exploration of the frontier acreage and building an understanding of the acreage requires many exploration activities and extensive analysis and interpretation of the data obtained from those activities…. Similarly, new play concepts take time to develop. Time has been allowed and should continue to be allowed for the concepts to be developed, as long as exploration is being progressed. 86

The EUAA and MEU also support the proposal for governments to play a more proactive role when specifying timeframes and when assessing applications to renew exploration and/or retention permits. They both noted, however, that these measures may need to be coupled with:

- greater consequences if producers fail to bring gas to market in a timely manner, through the stricter application of ‘use it or lose it’ provisions

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85 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-6 and Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.

86 Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1. Shell similarly stated that:

> 'Marginal and frontier exploration opportunities take time and understanding to progress from exploration to appraisal and production. It is difficult for any operator to make an accurate assessment of development potential at such an early stage of the process. Therefore, it is unrealistic to apply the same expectations for this acreage as is placed on proven development fields.'

Shell, Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 8.
• financial or other incentives to encourage producers to bring gas to market as quickly as possible. 87

Cooper and WestSide also noted that financial incentives or support could be offered to producers to encourage development within a specified time period. 88

To encourage gas to be supplied into the domestic market, the EUAA noted that there may be a need for wider application of Queensland's Australian market supply condition. The EUAA was not alone in supporting this mechanism, with a number of producers also supporting its use. Shell, for example, noted that the condition has brought on new sources of domestic supply and provides clarity on the investment conditions at the time of bidding, which it stated was 'preferable to regulatory intervention post investment'. 89 GLNG made a similar observation. 90

ACCC observations and recommendations

The ACCC encourages governments to consider playing a more proactive role when specifying the timeframes for exploration, appraisal and production activities and when deciding whether to allow exploration and/or retention permits to be renewed.

As Vintage and some other producers pointed out, there is no one-size fits all approach that can be employed when specifying timeframes for exploration, appraisal and production activities. That said, there does appear to be scope for governments to more actively encourage gas to be developed in a timely manner by:

• specifying shorter timeframes for exploration and appraisal activities than provided for in legislation where this is possible under the legislation and where appropriate to do so (e.g. when acreage is close to existing infrastructure and is of a high quality), and/or

• exercising the discretion, where possible, to refuse to renew exploration and/or retention permits for a second term.

3.3.3. Greater oversight of work programs could help bring gas to market in a more timely manner

In addition to specifying timeframes, governments also have a role in approving producers' work programs and monitoring and enforcing compliance with these work programs and permits, all of which can affect the timeliness with which gas is brought to market.

For example, if a larger producer wanted to try to 'bank' or 'warehouse' gas or otherwise slow the development of a new source of supply, then it may propose a slower work program than would otherwise be the case. It may also fail to comply with its approved work program if it believes the relevant government is not closely monitoring its activities and/or will not take action for non-compliance.

87 MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 1-3 and EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 1-2.

88 Cooper, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3 and WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.

89 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.

90 GLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 2.
Stakeholders agree that work programs should be closely monitored

In the issues paper, stakeholders were asked if governments should employ a more proactive approach when approving, monitoring and enforcing compliance with work programs.

The EUAA supported stronger government oversight of proposed work programs and the stricter application of use it or lose it provisions. It also suggested governments consider reserve write-downs when assessing a producer’s compliance with its work program.91

Vintage Energy also agreed that work programs should be monitored and complied with but noted there needs to be some flexibility to amend work programs over time as exploration is undertaken and data analysed because exploration involves a large number of unknowns.92

Shell noted the Queensland government already employs a proactive approach to enforcement of tenure compliance.93 Origin made a similar observation and noted there are already provisions within the legislative framework to enforce compliance and address any non-compliance by proponents.94

ACCC observations and recommendations

As a number of producers pointed out, there are already arrangements in place to allow governments to approve, monitor and enforce compliance with work programs. We do, however, consider that governments could play a more proactive role in this area, as the Queensland government does for onshore fields in Queensland and the National Offshore Petroleum Titles Administrator (NOPTA)95 does for offshore fields, to ensure that producers are not ‘banking’ or ‘warehousing’ gas and that gas is being brought to market in a timely manner.

The ACCC therefore recommends that governments:

• carefully consider proposed work programs and the timeframes assumed in these programs
• more actively monitor producers’ compliance with approved work programs
• be prepared to take action for non-compliance (including by requiring permits to be relinquished) where appropriate.

As chapters 1-2 highlight, the need for this is becoming increasingly important as the prospect of a supply shortfall becomes more likely and the market becomes more dependent on the development of new sources of supply.

3.4. Upstream competition and the timeliness of supply could be improved by reducing the barriers faced by producers

The second factor that we have examined is the effect that structural barriers can have on competition and the timeliness of supply. These barriers can be significant and directly affect both:

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91 EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.
92 Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 1-2.
93 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-6. In its submission, Shell also noted that a focus on overall project activity rather than individual tenure activity, would “better support industry”.
94 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5
95 We understand, for example, that NOPTA conducts regular monitoring of producer’s work programs and has required permits to be relinquished for non-compliance.
• the number of producers competing to supply gas in the east coast gas market (i.e. because these barriers can result in some producers entering into joint ventures with other producers, or selling their interests or raw gas to other producers),

• the timeliness with which gas is brought to market.

Some of the more significant barriers that producers have informed us they can face are:

• geological barriers, such as the permeability, depth, and tightness of the reservoir and the level of impurities in the reservoir, all of which can affect commercial recovery of gas

• infrastructure barriers, such as access to upstream infrastructure required to bring the gas to market (for example, gathering pipelines, natural gas processing facilities, and, in the case of coal seam gas production, water treatment facilities and compression facilities)

• commercial barriers, such as restrictions on access to capital and the relatively high costs associated with developing tenements

• regulatory barriers, such as land access, environmental and other regulatory approval requirements.

While there is little that can be done about geological barriers, there are steps that governments could take to help reduce some of the other barriers listed above.

3.4.1. Third party access to processing and other upstream infrastructure would aid competition and allow more marginal fields to be developed

Access to processing and other upstream infrastructure is a significant barrier that smaller producers and producers in more marginal fields have told us they can face when developing tenements.

In some cases, smaller producers have been able to overcome this by contracting directly with infrastructure service providers (for example, APA or Jemena), to develop and operate dedicated infrastructure on their behalf. A variant on this option is to develop common user processing and other upstream facilities in areas where there are a number of potential producers.

While these options may reduce the barriers faced by smaller producers, they may not result in the most economically efficient outcome and could adversely affect competition where there is existing underutilised upstream infrastructure in relatively close proximity to a tenement. Although access to existing infrastructure may be more efficient, there are only a small number of facilities actively offering to provide third party access.

While access to upstream infrastructure is not a new barrier, a number of producers have informed us it could pose more of a constraint on the development of gas in the future, given the increasing reliance of the market on more marginal tenements. We have therefore used our compulsory information gathering powers to get a better understanding of:

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96 Producers may, for example, either sell their interest in a tenement, or sell raw gas to a producer with processing facilities. In both cases, the sale effectively results in the producer not competing to supply gas to the east coast gas market.

97 These facilities include water processing facilities, pipelines and ponds.

98 See Appendix A.


100 The term ‘third party access’ is used in this context to refer to access being provided to any person other than the owner, a related body corporate of the owner or a joint venture partner of the owner.
the extent to which third party access to upstream facilities is already being provided

the requests that have been made to producers for third party access over the last five years which have not resulted in access being granted.

Based on our review of the information provided by the six producers that were asked about third party access, \(^{101}\) it would appear that:

- Four of the producers are currently providing third party access to one or more of their upstream facilities, or have done so in the past. In two of these cases, the producers are procuring some or all the gas produced by the access seeker.

- Five of the producers received requests to access one or more of their upstream facilities that did not result in access being granted. A total of 19 such requests were made over the five year period.
  - Of the 19 requests that were made, 16 were provided an offer. Producers cited technical reasons or the lack of a formal request for not providing offers in response to the remaining three requests.
  - Of the 16 offers that were made, seven were still under negotiation at the time we issued our notice. The reasons producers cited for the remaining nine offers not resulting in contracts include:
    - the prices offered were either equal to, or exceeded the cost of the access seeker developing its own infrastructure
    - the access seeker’s project not being mature enough to execute a contract
    - technical issues that impacted the ability of the parties to agree on contract terms.

The first of the reasons cited by producers for offers not resulting in contracts is consistent with what some access seekers have told us. It is also consistent with what we have seen in some internal negotiation material provided by producers. One producer, for example, noted in an internal briefing note that the price it originally offered an access seeker was based on its estimate of the access seeker’s next best alternative (i.e. the cost of the access seeker developing its own infrastructure), which was:

- close to 3 times the producer’s breakeven cost of providing access
- 1.3 times the price quoted by an infrastructure service provider to develop stand-alone infrastructure.

Even when it became aware of the alternative offer, the producer’s revised negotiation strategy involved trying to charge the access seeker a premium on the stand-alone cost of developing the infrastructure. One of the benefits of providing third party access cited by the producer in this case was that it would foreclose future competition from another infrastructure service provider:

\[\text{Tolling [access seeker’s gas and water] via [producer’s JV facilities] reduces the likelihood of third party processing infrastructure being developed and increases the presence of the [producer’s JV] in the area for the processing or acquisition of undeveloped reserves. [additions made to remove confidential information]}\]

In contrast to the bypass approach employed by this producer, another producer that is actively offering third party access to one of its facilities indicate that the prices it has agreed to have been calculated using the building block method commonly used by economic

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\(^{101}\) For the purposes of this analysis, we have excluded those cases where access is provided to a joint venture partner.
regulators. According to these documents, all the agreements on this facility are broadly consistent, with no party treated preferentially and price differences largely attributed to differences in gas composition. On another facility in which this producer has an interest (which is not actively offering third party access), internal documents reveal that the price it offered an access seeker was based on the cost of the next best alternative for that access seeker, rather than the cost of providing the service.

In confidential discussions we have had with a number of producers that have sought access, we have been informed that the inability to access existing infrastructure (or to do so on reasonable terms) has resulted in the unnecessary duplication of some processing facilities and other infrastructure. One of the examples cited by a number of these producers was the infrastructure developed for the Senex Atlas project, with a number of producers telling us it would have been more efficient to use QGC’s gas processing and water treatment infrastructure around Woleebee Creek than to develop new infrastructure.

In those cases where the tenements were too small to underwrite the development of new dedicated infrastructure, the inability to obtain access to existing infrastructure has also reportedly resulted in:

- the failure to develop some tenements
- some producers having to sell either their interests in the tenement, or the raw gas produced from the tenement to the producer that owns the upstream infrastructure.

While in the latter of these cases, gas may still be brought to market, competition will be more limited because the smaller producer will not compete to supply gas in the market.

Producers we spoke to also said that even where third party access is actively offered by a producer or infrastructure service provider, the infrastructure owner can wield substantial market power in negotiations, which can result in protracted negotiations and monopoly pricing. They also pointed to the parallels between gas pipelines and upstream infrastructure but noted that unlike gas pipelines, the owners of upstream infrastructure are not subject to any form of constraint when negotiating the terms and conditions of access.

Mixed views were expressed by stakeholders on whether owners of upstream infrastructure should be required to provide third party access on reasonable terms

In our issues paper, stakeholders were asked whether owners of upstream infrastructure with spare capacity should be required to provide third party access on reasonable terms, or if there are other ways to improve third party access to this infrastructure.

Stakeholders expressed a range of views on this issue. The EUAA and MEU, for example, submit that competition would be improved if owners of upstream facilities were required to do so. They suggest that these facilities be subject to a commercially-oriented third party access regime, similar to what currently applies to non-scheme pipelines under the NGL and NGR. The MEU also noted that a separate access regime could be developed and administered by the ACCC.

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102 The building block method is a bottom up cost method, that involves calculating the cost of providing the service. The costs that are typically taken into account under the building block method include: a return on the assets used in the provision of services, depreciation (i.e. a return of the assets used in the provision of services, operating expenditure and net tax liabilities.


104 The term ‘monopoly pricing’ is defined as prices that significantly exceed the long-run average cost of supply for a sustained period. Or put more simply, prices in excess of what would prevail in a workably competitive market.
Vintage submitted that:

*In other parts of the world, once infrastructure has been fully depreciated or cost recovered then excess capacity is made available to third parties at a reasonable cost. This should be considered in Australia, as access to infrastructure and negotiating that access can be very difficult and drawn out.*

Arrow agreed that access to upstream infrastructure can be a significant barrier and noted that its collaboration with QGC in the Surat Gas Project was a good example of third party access helping to bring gas to market and noted that without this, the project would not have been economically viable. It also noted that the Moranbah Gas Project has recently entered into an arrangement to provide access to a compression facility and that Arrow is looking for other opportunities to share infrastructure. While Arrow did not express a view on whether third party access should be required, it did suggest that greater transparency of spare capacity on upstream facilities could help to facilitate access.

In contrast to these submissions, APPEA, APLNG, Origin, Shell and WestSide submitted that owners of upstream infrastructure already have an incentive to sell any spare capacity they may have and that rather than mandating access, this should be left to commercial negotiations. They also noted there can be significant complexities and challenges associated with providing third party access to upstream infrastructure, which must be taken into account. Elaborating further on its position, Shell noted:

*Shell is open to making available spare upstream infrastructure capacity on commercial terms and has worked with several domestic CSG parties …to explore opportunities with the QCLNG project. Shell considers that the provision of spare upstream infrastructure capacity to third parties needs to be on commercial terms, so owners of infrastructure can determine the availability, impact on current production and reasonable compensation for the risk and investment made in the infrastructure. Any requirement to offer capacity on a regulated basis to third parties is expected to have a significant impact on long-term business planning for owners of such infrastructure.*

*While in theory, it may appear that connecting to existing spare capacity is the most logical approach, in reality, connecting to third party infrastructure comes with several complexities that need to be addressed to the mutual satisfaction of the parties…*

*…a regulated approach to providing third-party access is unlikely to take into consideration all nuances of a particular situation and would likely result in a sub-optimal outcome, not only for existing infrastructure owners but also potentially for parties seeking access to such infrastructure.*

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105 Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.
106 Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 3-4.
107 Ibid.
108 APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 6.
109 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 8.
110 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 11-13.
111 WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.
112 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 11-12.
Santos similarly stated that:

While Santos is providing access to infrastructure, currently there are not a large number of customers taking up this opportunity. Santos is providing access to the Moomba production facility for Santos operated JVs (~90% throughput) and Beach operated JVs (~10% throughput). Future third party opportunities are being discussed with other companies although these are not large volumes and are relatively immature.

Negotiating third party access to infrastructure is achievable, but there are unique challenges, including the availability of upstream infrastructure capacity (e.g. satellite compression and pipelines). There needs to be sufficient capacity in pipelines and processing facilities so that existing users do not lose access which could increase the risk of them not being able to meet supply commitments. Mitigating this risk may mean that the upstream infrastructure owner cannot provide third parties a firm service. Without a firm service, a producer will struggle to commit to a gas sale agreement.

Providing third party access to upstream infrastructure is achievable (as demonstrated in Cooper Basin). Infrastructure owners should already be incentivised to allow third party access although any barriers to third party access may need further discussion with market participants.113,114

Origin also noted that:

There are coordination issues and costs from sharing a gas processing facility with other parties. These can include the need for plant modifications to ensure that the facility is compatible with the particular chemical composition of a third party’s gas and loss of flexibility in the operation of, and investment in, the facility.

Even where there is seemingly a low level of utilisation, this is not necessarily a sign of inefficiency or an indication that capacity is available at a particular point in time. This is because contractual arrangements often provide customers with flexibility to change the rate of nominated quantities on a daily or even hourly basis, meaning required/utilised capacity can be significantly higher than average production volumes at any point in time.115

In addition to asking about access to upstream infrastructure, the issues paper asked stakeholders whether third party access to any other infrastructure, such as storage facilities or LNG processing facilities, could help to facilitate more upstream competition and/or more timely development of supply. While there was one stakeholder that thought third party access to storage would facilitate upstream competition,116 other stakeholders were silent on this issue.

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113 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, pp. 7-8.
114 GLNG similarly observed that:

Upstream infrastructure (e.g. gathering pipelines, gas processing facilities and/or water processing facilities) are generally part of a fully integrated coal seam gas production facility, pipeline system and LNG facility. The assets forming the fully integrated systems have been specifically designed and correctly sized to meet the specific needs of the relevant system. They are designed to operate with precision to optimise the system and respond to gas supply and demand changes and planned and unplanned events in the upstream and downstream operations. This optimisation is essential to maintaining reliability across all assets.

GLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 7.
115 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 8.
116 MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.
As to LNG processing facilities, there were no stakeholders that thought third party access to these facilities would help to facilitate upstream competition or the timely supply of gas to the market. Elaborating on this further, CNOOC stated that access to LNG processing facilities would ‘have the opposite impact’ to what was intended by the review, because it would result in a:

...decrease in competition in the upstream and cause supply constraints in the domestic market. The domestic market participant may choose to remove their excess gas available for domestic sale and choose to export LNG overseas.\(^\text{117}\)

GLNG similarly observed that:

LNG facilities are generally part of a fully integrated coal seam gas production facility and pipeline. These fully integrated systems have assets that have been specifically designed and correctly sized to meet the specific needs of the relevant system. They are designed to operate with precision to optimise the system and respond to gas supply and demand changes and planned and unplanned events in the upstream and downstream operations. This optimisation is essential to maintaining reliability across all assets.

Further, reliability of gas production and having interruptible gas transportation systems are essential for ensuring that GLNG can operate safely and within design specifications to produce the required volume of LNG cargoes needed to meet its SPA commitments and provide volumes of gas to support the domestic market and consequently significantly support the Australian economy. This cannot be achieved if LNG processing facilities and storage facilities become open to third party access.

Imposing third party access on these facilities are likely to:

- erode the substantial existing investment in Australia’s gas industry,
- make ongoing and future investment in Australia’s gas industry unattractive at a time when there is a highly competitive global market,
- is contrary to the Federal Governments strategy to develop a gas fired COVID economic recovery and
- consequently, significantly impact the many Australians who benefit from the current significant investment in the Australian gas industry.\(^\text{118}\)

ACCC observations and recommendations

The ACCC recommends that governments consider introducing a third party access regime for upstream infrastructure (i.e. gathering pipelines, natural gas processing facilities, water treatment facilities and compression facilities) and storage facilities.

As a number of access seekers have noted, there are some important parallels between gas pipelines and both upstream infrastructure. Like gas pipelines, upstream infrastructure exhibits natural monopoly characteristics\(^\text{119}\) (because investments in pipelines are indivisible, economies of scale exist, and sunk costs are large).

These characteristics mean that access to existing infrastructure is often more economically efficient than constructing new infrastructure. Natural monopoly characteristics can also accord the owner substantial market power, which can be exercised in a number of different

\(^\text{117}\) CNOOC, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.

\(^\text{118}\) GLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 6.

\(^\text{119}\) The term ‘natural monopoly’ is used to refer to a situation where a single firm can supply a market at a lower overall cost than if it were supplied by multiple firms.
ways. The owners may, for example, exert market power by engaging in monopoly pricing, or in the case of vertically integrated service providers, restrict or deny access, as a number of access seekers we have spoken to have observed.

Irrespective of the form it takes, exercises of market power can have a detrimental effect on economic efficiency and consumers more generally, because it can result in prices being set above, and/or the supply of services below, what would occur in a workably competitive market. This can, in turn, have a detrimental effect on the efficient operation of the gas market, upstream and downstream markets and the broader economy, because it can result in lower than efficient levels of production, consumption and investment.

In economic terms, this is a form of ‘market failure’ because the market does not work to allocate resources in the most efficient manner across the market and the broader economy. In such circumstances, there may\(^{120}\) be value in governments intervening to improve efficiency and to achieve better outcomes for the market and consumers more generally.

In this regard, it is worth noting that the national access regime in Part IIIA of the CCA cannot effectively address this market failure for upstream infrastructure facilities in its current form, because the definition of service in section 44B of the CCA expressly excludes access to services provided by means of a facility that involves the use of a production process. Another issue with Part IIIA is, it generally is only relevant to a denial of access to nationally significant infrastructure by vertically-integrated facility owners. It does not deal with monopoly pricing by infrastructure that is not vertically-integrated. While most of the owners of upstream infrastructure are vertically integrated, there a number that are not, but access to these facilities has also reportedly been problematic, with the owners seeking to exercise their market power by engaging in monopoly pricing.

The ACCC has publicly advocated for reform to the national access regime to provide a mechanism to deal with monopoly pricing of infrastructure in any industry. However, until such reform is undertaken, the national regime cannot address the issues we have observed with access to upstream infrastructure (i.e. denial of access and monopoly pricing).

As an alternative to the national access regime, an industry specific access regime could be implemented by amending the NGL and the NGR. The NGL and NGR already include a third party access regime for gas pipelines. As noted in chapter 6, this regime is currently being amended to give effect to Energy Ministers’ decision to implement a simpler regulatory framework that will support the safe, reliable and efficient use of and investment in pipelines, while also posing more of a constraint on market power and providing greater support for commercial negotiations.\(^{121}\)

Under the amended access regime, all pipelines will be required to provide third party access (including those that were built to just service the owner’s needs) if requested to do so and subject to either:

- a stronger regulatory focused form of the negotiate-arbitrate model, which is underpinned by economic efficiency principles. Under this form of regulation, pipelines will be required to have their reference tariffs approved by the regulator on an \textit{ex-ante} basis and will also need to comply with the information disclosure obligations and negotiation framework set out in the NGR. Users will be able to have recourse to a regulatory-oriented dispute resolution mechanism if negotiations fail

\(^{120}\) The term ‘may’ is used here because the presence of a market failure is a necessary, but not sufficient condition, for government intervention. Intervention should only occur if it leads to a better outcome than that which would occur in its absence, after accounting for the costs of implementing the intervention.

• a lighter commercially focused form of the negotiate-arbitrate model, the objective of which is to facilitate access on reasonable terms. That is, at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market. Under this form of regulation, pipelines will be required to comply with the information disclosure obligations and negotiation framework set out in the NGR. Users will also be able to have recourse to a commercially-oriented dispute resolution mechanism if access negotiations fail.

In a similar manner to what Energy Ministers have agreed for pipelines, if an industry specific access regime for upstream infrastructure was to be implemented, then we would suggest that the operators of all upstream infrastructure facilities be required to provide access if requested to do so. We also suggest that this form of infrastructure only be subject to the lighter commercially focused form of the negotiate-arbitrate model and not to the stronger regulatory focused form of regulation. This is because the costs of applying the stronger form of regulation are more likely to exceed the benefits, given the limited number of parties that are likely to seek access to upstream infrastructure facilities.122

If the lighter handed form of regulation was applied, it should provide a credible threat of intervention by an access dispute body that should constrain any potential inefficient monopoly pricing or other exercises of market power (e.g. restricting or prohibiting access where it would be feasible to provide access). It would also allow access seekers and infrastructure owners to continue to undertake commercial negotiations (as a number of producers have stressed the importance of), while also providing greater support for these negotiations through:

• the information disclosure obligations that infrastructure owners would be subject to, which should reduce the information asymmetries that access seekers may otherwise face and, in so doing, facilitate more informed negotiations and decision making
• the negotiation framework that infrastructure owners would be required to comply with, which should facilitate more timely and effective commercial negotiations and address concerns some access seekers have about long and protracted negotiations
• the commercially-oriented dispute resolution mechanism, which should:
  o constrain exercises of monopoly pricing, denial or restriction of access, or other forms of market power by the infrastructure owner during negotiations (i.e. by providing for a credible threat of intervention by a commercial arbitrator if negotiations fail)
  o enable those disputes that cannot be resolved through negotiations to be resolved in a cost-effective and efficient manner.

The application of this lighter handed model to upstream infrastructure can therefore be expected to result in access being provided to facilities that may not otherwise have provided such access and at lower prices than may otherwise have been charged. This would, in turn:

• reduce the need to inefficiently duplicate upstream infrastructure
• allow gas from tenements that would not otherwise have been developed, because they were not of a sufficient scale to underwrite infrastructure, to be supplied into the market
• allow producers that may have otherwise had to sell their interests in the tenement, or the raw gas produced from the tenement, to the infrastructure owner, to compete in their own right to supply gas in the market.

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122 When there are a number of parties seeking access to a facility, there can be value in having a regulator approve a reference tariff, because it can be a lower cost option than each access seeker trying to establish what an appropriate price for access is and potentially going to arbitration.
The application of this lighter handed model can therefore be expected to generate a range of allocative, productive and dynamic efficiencies and facilitate more effective upstream competition, the ultimate beneficiaries of which will be consumers of natural gas and the economy, more generally.

While some producers have expressed concerns about the ability of this type of regime to account for the technical requirements of upstream infrastructure and an infrastructure owner’s own use of the facilities, these are matters that, in our view, can be effectively accommodated. The lighter form of regulation applying to gas pipelines, for example, currently provides that:

- service providers do not have to make an offer if they conclude it is not technically feasible or consistent with the safe and reliable operation of the pipeline to provide the service, having used all reasonable efforts to accommodate a user’s requirements.123
- the commercial arbitrator to take into account the operational and technical requirements necessary for the safe and reliable operation of the pipeline124 and the legitimate business interests of the service provider when making an access determination.

To the extent that there are any additional technical requirements that would need to be taken into account for upstream infrastructure, this could be accommodated in a similar way.

Finally, while not many stakeholders raised access to storage as a barrier to upstream competition or the timely supply of gas, there are some important parallels between storage facilities, gas pipelines and upstream infrastructure. Storage facilities are, for example, natural monopolies and the owners of these facilities have both the ability and incentive to exercise market power. As conditions in the market become tighter and the risk of shortages become more likely, access to storage is likely to be even more important. We suggest, therefore, that consideration be given to applying a third party access regime to storage facilities.

We understand that Energy Senior Officials are currently consulting on options to advance the east coast gas market and that as part of this process are considering whether improved access by third parties to upstream infrastructure, storage, compression and LNG facilities could lower barriers to entry and deliver other benefits to the gas market.125 We therefore suggest that, as part of this consultation process, Senior Officials consider implementing a third party access regime for both upstream infrastructure facilities and storage facilities. Constraints on access to capital and long-term contracts to underwrite investments could impede some developments.

Access to the capital required to undertake exploration and appraisal activities and to move into production can pose a significant barrier, particularly for smaller producers.

A number of smaller producers have, for example, informed us that accessing capital can be difficult, particularly during the exploration stage.126 Smaller producers have also told us it can be challenging to find buyers willing to enter into long-term GSAs required to underwrite projects. More generally, producers have informed us that it is becoming increasingly difficult to obtain finance for fossil fuel related projects.

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123 See rule 560(4).
124 See rule 569(c).
126 They also noted that it can take a considerable amount of time to move from exploration to production, during which time they are typically reliant on equity finance and subject to significant financial strain.
Some stakeholders are calling for more government support to overcome the barriers posed by access to capital and underwriting

In the issues paper, we asked stakeholders whether there were any effective ways to reduce these barriers. Most stakeholders agreed that access to capital can represent a significant barrier for smaller producers. They also agreed that environmental, social and governance concerns may start to limit the availability of debt and equity funding for gas projects. Santos for example, noted that:

> Capital constraints are a live issue for producers of all sizes, along with increasing difficulty in securing debt funding. New developments need sufficient 1P or 2P reserves to underpin long term contracts for project FID at prices that meet required hurdle rates for the risk taken. Access to capital and managing risk are key reasons why upstream assets are typically developed through a joint venture structure.

> Increasing ESG pressure is tightening access to capital with banks increasingly under pressure from their own investors to not fund projects in the fossil fuel sector. Lenders and insurers are progressively implementing policies which constrain capital resources for projects. In addition, pressure from equity investors to reduce emissions and establish credible pathways to net-zero emission means less capital is available for upstream developments... These factors are expected to increasingly impact competition as producing companies need to secure capital or fund projects from their own balance sheet. This is also likely to limit the ability for smaller players to enter the market with scale to self-fund investments becoming increasingly important.127

For those producers that are able to make the transition from exploration to production, finding buyers that are willing to underwrite the development by entering into the long-term GSAs can also be challenging, as Senex noted in its submission:

> The most material barrier to Senex’s initial development in the Surat Basin was not subsurface design and engineering, land access, access to capital, or access to infrastructure. It was access to market. Our challenge was finding buyers prepared to underwrite the development.128

To overcome these barriers, the EUAA, MEU and a number of smaller producers, including WestSide, Cooper, Senex and GLNG, suggested that state, territory and/or Commonwealth governments provide some form of financial support. The forms of financial support that were identified in this context include:

- grants or other financial incentives to encourage gas to be brought to market more rapidly129
- concessional loans (similar to the NAIF financing),130,131 or other credit enhancement options to make it easier for producers to access capital132

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127 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 8.  
128 Senex, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 4.  
129 Cooper, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3 and MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 2.  
130 WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.  
131 As set out on NAIF’s website, its primary financing mechanism is the provision of fixed rate loans. NAIF also has the ability to provide concessions on the interest rate (which cannot be below the cost of Commonwealth borrowing and administrative costs) on the basis that the concessions are limited to the minimum necessary for a project to proceed. https://naif.gov.au/about-naif-finance/.  
132 MEU, for example, noted that governments could use their “favourable credit ratings, balance sheets, and become a low-cost financier for exploration and development projects: MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021.
• direct underwriting\textsuperscript{133} for new gas developments.

In relation to the latter of these, GLNG noted that:

\textit{Commonwealth, State and Territory governments could encourage diversity in the upstream market and assist in bringing more gas to market in a timely manner by directly investing in or underwriting the infrastructure capital needed to bring that gas to market. This is likely to open up development in gas reserves located in the Bowen and Galilee Basins for example.}\textsuperscript{134}

APPEA also noted that it has provided governments with an investment recovery blueprint that focuses on improving fiscal settings, including investment allowances, to support exploration and development.\textsuperscript{135}

\textbf{ACCC observations and recommendations}

There is always a risk when governments provide financial support of the nature suggested by some stakeholders that it will crowd out market-driven investment and have a deleterious effect on other investment decisions across the market. The ACCC is therefore cautious about governments intervening in the market in this manner. Rather, in the ACCC’s view, market participants are better placed to assess the relative benefits of different investment options within the gas sector and more broadly between all sectors in the economy.

That said, governments can play a role in enabling market participants and financiers to make more informed decisions about investment in the market. The Commonwealth government’s Strategic Basin Plans and National Gas Infrastructure Plan are good examples of the steps that governments can take to try and reduce the information asymmetries and address co-ordination failures that may otherwise be discouraging market-based investment. The National Gas Infrastructure Plan, for example, identifies higher priority projects that are required to address projected shortfalls and which are likely to generate sufficient returns to proceed, based on market conditions.

\textbf{3.4.2. Reducing regulatory barriers would help to foster a more competitive upstream market and provide for more timely supply}

To undertake exploration, appraisal and/or production activities, producers must obtain the relevant regulatory approvals (including environmental approvals) from state/territory governments and/or the Commonwealth government. For onshore developments, they must also negotiate land access agreements with landowners.

\textbf{Stakeholders identified a large number of regulatory barriers that could be reduced}

In the issues paper, we asked stakeholders whether there were any effective ways to reduce the impediments posed by regulatory barriers.

In response to the issues paper, producers identified many regulatory barriers they claim are affecting the timeliness with which gas is being brought to market and limiting competition. This includes:

• bans, moratoria and other regulatory restrictions on onshore exploration and development\textsuperscript{136}

\textsuperscript{133} Senex, for example, noted that government underwriting would guarantee "a return sufficient to justify the development risk, ahead of customer commitments". Senex, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021.

\textsuperscript{134} GLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 5.

\textsuperscript{135} APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 27.
• multiple and duplicative regulatory approvals processes (both within jurisdictions and across federal and state/territory governments),\textsuperscript{137} and the lack of statutory timeframes and/or statutory resolution mechanisms for decisions in some jurisdictions\textsuperscript{138}

• the protracted nature of the gazetted processes used to release acreage in some jurisdictions,\textsuperscript{139} and the reliance placed on tenders rather than direct applications for frontier acreage in some jurisdictions\textsuperscript{140}

• limitations in legislation that may restrict transfers of tenure between producers\textsuperscript{141}

• the arrangements for negotiating of land access\textsuperscript{142}

\textsuperscript{136} APPEA, for example, noted that bans, moratoria and other regulatory restrictions have “prevented new entrants into the east coast gas market, significantly limited competition and provided the most direct and significant impediments to the timely supply of gas”. APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5. GLNG also raised this as an issue. In doing so it noted that:

\textit{Between 2001 and 2012, 35 separate exploration licences were granted in Victoria - all of which are now cancelled, expired, surrendered or dormant (16 current) (“Inquiry into onshore unconventional gas in Victoria, Final Report”, 2015). For almost 10 years since August 2012, the Victorian Government has had effective holds on approvals to undertake onshore gas exploration and the issuing of gas exploration licences. The ensuing moratorium was only partially lifted this year in July 2021.}

\textit{Similarly, gas developments in NSW have been impeded by moratoria and regulatory reviews and legislative changes since around 2012. NSW went from one of the least regulated systems to one of the most convoluted regimes. NSW has ready to develop reserves, but its recently released Future of Gas Statement means that only the Narrabri Gas Project can ever be developed.}

GLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 1. Santos made a similar observation, noting that:

\textit{…it has been government intervention that has slowed down the bringing on of new supply from projects Santos has been willing to invest in, in both NSW and the NT. Our Narrabri Gas Project has been delayed for the best part of a decade because of moratoriums and inquiries into the environmental safety of the industry, lengthy approval processes and judicial challenges to those approvals, despite Santos investing more than A$1.5 billion so far. Similarly in the NT, moratoriums and inquiries have delayed exploration and development of the highly prospective McArthur Basin for more than half a decade.}

Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 1.

\textsuperscript{137} APLNG, Origin, Shell, Cooper and WestSide pointed to a number of examples of duplication in their responses. APLNG, for example, noted that there is duplication across the water approvals process (with duplicative information and approvals processes required by both state and Commonwealth governments), which has led to significant delays. APLNG also noted that the approvals process which has significantly delayed approvals.

Cooper also expressed concerns about the misalignment of some between some legislative instruments, such as the Commonwealth Offshore Petroleum Greenhouse Gas Storage Act and the Petroleum Resource Rent Tax Act.

APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-5, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 6-8, Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 9-10, Cooper, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3 and WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. a3.

APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-5, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 6-8, Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 9-10, Cooper, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3 and WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. a3.

\textsuperscript{138} Origin and APLNG, for example, stated that the current framework does not provide any timeframes for decision-making, which gives rise to uncertainty for proponents seeking approvals for exploration, appraisal and/or production. APLNG also noted that it had recently waited two years for a petroleum lease to be granted. APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 1-2, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 4.

Arrow made a similar observation in its response. See Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 2.

\textsuperscript{139} Vintage, for example, stated that the gazetted process is too slow in some jurisdictions, which delays exploration and potential discoveries. Vintage, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.

\textsuperscript{140} APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.

\textsuperscript{141} APLNG, for example, noted that the Queensland resource legislation does not readily facilitate transfers of tenure between producers, because the focus is on compliance of the existing tenure holder, rather than the capacity of the proponent.

\textsuperscript{142} Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 10.
• changing tax and royalty regimes.\textsuperscript{143}

On the first of these matters, producers noted that while some improvements had occurred over the last two years, the bans, moratoria and other regulatory restrictions in place in Victoria, NSW and Tasmania were still impeding exploration and development. They suggested these restrictions be lifted. Origin also suggested that restrictions on exploration and development in the Northern Territory be removed by implementing the recommendations from the 2018 Northern Territory fracking inquiry.\textsuperscript{144}

In relation to the other matters, producers noted that improvements could be made in these areas without compromising the quality of the approvals processes or the outcomes. They suggested that governments streamline and harmonise their regulatory approvals processes (both within and across governments) and, in doing so, remove the duplication and other limitations and sources of uncertainty from the regulatory framework.

A number of producers also suggested that a single regulator in each jurisdiction be responsible for regulatory approvals and that bilateral arrangements be put in place between state/territory and Commonwealth governments to ensure the regulator gives effect to the requirements under state/territory and Commonwealth legislation.\textsuperscript{145}

Some producers also suggested the adoption of a centralised case management approach for regulatory approvals in each jurisdiction, with case managers responsible for obtaining cooperation and alignment across government departments and helping producers navigate the process.\textsuperscript{146}

We understand that some of these matters are being considered by the Queensland Government's Department of Resources as part of its resources industry development plan.\textsuperscript{147}

The MEU and EUAA also support greater harmonisation of regulatory processes across state, territory and Commonwealth governments. They also suggest that the 'use it or lose it' provisions be harmonised to, in the words of the MEU, 'put pressure onto tenement holders to maximise their efforts to get gas to the market and so increase competition'.\textsuperscript{148} The EUAA also suggest that governments consider supporting smaller producers through the process to improve their ability to participate in tenders and to comply with their permits.\textsuperscript{149}

**ACCC observations and recommendations**

The ACCC recommends state, territory and Commonwealth governments consider the feedback provided by stakeholders and take active steps to reduce regulatory barriers to exploration and development.

\textsuperscript{143} WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.

\textsuperscript{144} Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 7-8.

\textsuperscript{145} APLNG, for example, noted that the Commonwealth and Queensland governments have entered into a bilateral agreement for the assessments required by the Commonwealth's Environmental Protection and Biodiversity Conservation Act 1999 and suggested this be extended to include approvals. See APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5.

\textsuperscript{146} WestSide, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1.

\textsuperscript{147} Queensland's Department of Resources, *Queensland resources industry development plan - draft for consultation* – November 2021

\textsuperscript{148} MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 1 and EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021.

\textsuperscript{149} EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 2.
Many of the regulatory barriers cited by stakeholders are, as one stakeholder put it, ‘beyond the ACCC’s purview’.\textsuperscript{150} It would, however, appear that efficiencies could be achieved if state, territory and Commonwealth governments were to work together to:

- streamline and, where appropriate, harmonise regulatory processes (including by reducing the degree of duplication in these processes, particularly between the Commonwealth and states/territories)
- put in place measures to help producers navigate the approvals process
- address other limitations and sources of uncertainty in the regulatory framework.

If this was to occur, the costs of securing regulatory approvals could be substantially reduced, without affecting the quality of the approvals process. This would, in turn, reduce the barriers producers (particularly smaller producers) currently face, which would help to foster the development of a more competitive market over the medium to longer term. It would also allow gas to be brought to market more rapidly.

As the risk of a supply shortfall becomes more likely, the ACCC also strongly encourages governments not to adopt blanket moratoria or bans on exploration or development. Rather, as we have previously recommended, governments should consider the risks of individual gas supply projects on a case-by-case basis.

\textsuperscript{150} APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021.
4. Domestic price outlook

4.1. Key Points

- Prices offered for 2022 supply in the domestic market increased over mid-2021.
  - Prices offered for 2022 supply by gas producers increased from a range of $6.50–8.20/GJ in late 2020 and early 2021 to $6.70–9.40/GJ between March and August 2021. Over this period, prices offered by retailers also increased from $6.00–9.00/GJ to $7.20–9.60/GJ.
  - These increases were modest compared to significant increases in expected LNG netback prices during the first half of 2021 (which were due to forecasts of a global supply crunch in LNG markets during 2022). As a result, many domestic offers have been below export parity prices more recently.
    - Expected 2022 LNG netback prices overtook prices offered for 2022 supply in Queensland and the southern states in March and April 2021, respectively.
    - Despite a forecast shortage in the southern states in 2022, prices offered for 2022 supply clustered around seller alternative levels in mid-2021 for the first time since the beginning of the Inquiry.
  - There were significantly more bids and offers from March 2021 onwards than in late 2020 and early 2021, with market activity also exceeding January–August 2020 levels during this period.
  - Prices payable under GSAs for supply to southern states in 2022 under producer fixed price contracts increased to $7.5/GJ on average during March–August 2021. Similarly, prices payable under retailer GSAs increased to $8.2/GJ over the same timeframe.
  - LNG producers have improved their documentation of offers made to the domestic market for exported uncontracted gas. This followed amendments to our notices to enable greater scrutiny of compliance with the Heads of Agreement. However, we remain concerned about how some exporters have approached demonstrating compliance:
    - It is unclear whether some gas originally offered in some EOI processes was ultimately able to be supplied to domestic customers and whether reasonable notice was provided.
    - Many domestic offers from LNG producers do not appear to have been internationally competitive. Some exporters have also provided insufficient information regarding their consideration of LNG prices when making domestic offers.
    - We are concerned about an exporter’s reliance on short term offers made to the Wallumbilla Gas Supply Hub. While likely compliant with the Heads of Agreement, this form of market engagement may not meet the needs of many domestic buyers.

4.2. Introduction

This chapter presents information on wholesale gas commodity prices in the east coast gas market for supply in 2022.\footnote{The east coast gas market consists of Queensland, New South Wales, Victoria, South Australia, the Australian Capital Territory and Tasmania.}

Specifically, the ACCC reports on:

- prices offered and bids received by gas producers and retailers (section 4.4.1)
• prices offered in Queensland and the southern states relative to expected LNG netback prices (section 4.4.2)
• prices agreed by gas producers and retailers (section 4.5.1)
• the level of flexibility agreed by producers and retailers (section 4.5.2).

This chapter also assesses compliance with the Heads of Agreement between the east coast LNG producers and the Australian Government (section 4.6.1).

Prices reported in this chapter reflect wholesale gas commodity prices in offers, bids and gas supply agreements (GSAs) which have a term of at least 12 months, an annual contract quantity (ACQ) of at least 0.5 PJ, and are made or entered into at arm’s length. A complete explanation of the ACCC’s approach to reporting on prices is presented in appendix B.

Where the ACCC reports on an average price in this chapter, it is a quantity-weighted average wholesale gas commodity price.

4.3. Recent trends in international oil and LNG prices and domestic short term market prices

As discussed in previous inquiry reports and our LNG netback price series review, LNG prices influence domestic suppliers’ opportunity cost of supplying gas to the domestic market and therefore influence domestic prices.\(^\text{152}\) Our review of supplier pricing strategies found that oil prices have also been a key factor in domestic pricing in recent years.\(^\text{153}\)

We have considered recent changes in international LNG and oil prices, as well as domestic short term markets, given their influence on GSA prices in the east coast gas market.

**Chart 4.1: Historical and future Brent Crude and JKM Prices**

Source: ICE, S&P Global Platts, EIA, ACCC analysis.

\(^\text{152}\) ACCC, *LNG netback review: Final decision paper*, p. 15.

\(^\text{153}\) ACCC, *Gas Inquiry Interim Report*, July 2021, p. 44.
Commodity prices have rebounded since early 2020. We have seen large increases in Brent Crude and JKM over the reporting period. However, they have not increased at the same rate.

Chart 4.1 presents historical and expected futures prices for both Brent and JKM. Brent Crude prices fell to a USD18.38 per barrel low in April 2020 in part because of the turmoil caused by the onset of the COVID-19 pandemic. However, since then, Brent Crude prices have increased rapidly, reaching a peak of USD83.54 per barrel in October 2021. Brent Crude futures data suggests an expectation of elevated prices throughout 2022, with prices gradually declining to USD74.81 per barrel in December 2022.

JKM prices spiked to an all-time high in November 2021, following a sustained increase in European gas prices and a global energy shortage. JKM futures indicate the market expects high prices to persist during Q1 2021 before declining to USD18.10 per MMBtu in April 2022.

Chart 4.2: Average 2022 JKM and Brent Crude oil futures prices (indexed at 1 March 2021)

Chart 4.2 demonstrates the relative difference in price increases between JKM and Brent Crude oil futures for delivery in 2022.

Until mid-April, average 2022 JKM and Brent Crude oil futures grew at roughly the same rate. However, after this point the growth rate in futures prices diverged. Relative to March, average 2022 JKM futures prices increased by approximately 85% more through to the middle of August than average 2022 Brent futures prices.

JKM futures prices for 2022 increased steeply from April onward, due to growing forecasts of a supply crunch in global LNG markets over the 2021-22 Asian winter. Expected 2022 JKM prices exceeded US$13/GJ in August, almost double expected levels in March, following surging Asian and European LNG spot prices.

Brent Crude oil futures were more stable over this period, increasing by approximately 20% between March and August 2021.
Chart 4.3 shows daily prices in domestic short term markets from 1 March to 4 August 2021. Domestic short term prices appear to have been broadly consistent with LNG netback prices throughout 2021 up to July, when short term prices increased significantly and above netback levels. As noted by the AER in its Wholesale Markets Quarterly report for Q3 2021, the price increases over July were driven by domestic factors including residential heating requirements combined with GPG demand and supply constraints in Victoria. These issues were largely resolved by August and September 2021, with domestic short-term prices falling and appearing to de-link with LNG netback prices during these months.154

4.4. Prices offered for supply in 2022 increased moderately in mid-2021, but not in line with significant increases in LNG netback

In reporting on offers made and bids received by suppliers, we included only those offers and bids that contain clear indications of price, quantity, supply start and end dates, and estimated the price for each offer and bid using the approach outlined in appendix B.

The analysis of offer and bid prices in this chapter is intended to provide an indication of price trends over time. As explained in appendix B, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects, such as delivery location, quantity, contract term and contract flexibility. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil), price expectations over the length of the contract (not only the supply year in discussion) or, in the case of GPG, conditions in the electricity market.

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154 AER, Wholesale Markets Quarterly Q3 2021, November 2021, p. 36.
### 4.4.1. Prices offered for supply in 2022 increased in mid-2021

Chart 4.4 shows offers made by producers and retailers for 2022 supply over the period from 1 January 2020 to 12 August 2021.

**Chart 4.4: Gas commodity prices (2022$/GJ) offered in the east coast gas market for 2022 supply**

Prices offered for supply in 2022 declined significantly in the first half of 2020 and remained stable across the remainder of the year. By comparison, prices offered increased in early 2021 and maintained an upwards trend through to August 2021.

From mid-2021, offers made by producers for supply in 2022 were between $6.7–$9.4/GJ, increasing from a range of $6.2–$8.2/GJ in late 2020 and early 2021. Following wider price dispersion between March and May 2021, producer offers concentrated around $7.2–8.8/GJ between June and August.

Similarly, prices offered by retailers for 2022 supply trended upward towards the middle of 2021, with offers in the range of $8.2–$9.6/GJ during late July.

Following a reduction in reported offers in late 2020 and early 2021, market activity increased significantly, with approximately 175% more offers reported between March and August 2021 than between September 2020 and February 2021. Market offer activity between January and August 2021 also exceeded the same period in 2020.

Chart 4.5 compares the quantity-weighted average price of offers made and bids received by producers (to all buyers) and by retailers (to all C&I users) for gas supply in 2022 in three periods:
January 2020 to August 2020, which shows a relatively wide dispersal of prices offered by producers and retailers for supply in 2022.

September 2020 to February 2021, which captures the period of reduced participation by producers and retailers in the market from late 2020 to early 2021.

March 2021 to August 2021, which was a period of increased offer activity and shows a rebound in prices offered by producers and retailers to those offered in early 2020.

**Chart 4.5: Gas commodity prices (2022$/GJ) offered and bid in the east coast gas market for 2022 supply**

**Source:** ACCC analysis of offer information provided by suppliers.

**Note:** Quantity-weighted average prices are displayed below the price range. Bids made to retailers were excluded from the chart because an insufficient number of bids were made to retailers by C&I users.

Between March and August 2021, quantity-weighted average prices rebounded to prices similar to those seen between January and August 2020 following a decrease in prices offered and bid between September 2020 and February 2021.

Market activity also rebounded between March and August 2021 to levels seen from January to August 2020, following a significant decrease in the number of offers made during the preceding period. Producers and retailers combined made over twice as many offers between March and August 2021 than in the previous period for supply to the east coast. Similarly, buyers made almost twice as many bids to producers between March and August 2021 compared to the two earlier periods combined.

Quantity-weighted average prices offered by producers increased between late 2020 and August 2021, with average prices rising from $7.25/GJ between September 2020 and February 2021 to $7.66/GJ between March and August 2021. This represents a 6% increase, however quantity-weighted average offers between March and August 2021 remained lower than those offered between January and August 2020.
Quantity-weighted average prices in bids received by producers also increased during March to August 2021 from $6.20/GJ to $7.26/GJ, representing a larger increase of 17% in average bids for 2022 supply.

Prices offered by retailers to C&I users similarly increased on average from $7.29/GJ between September 2020 and February 2021 to $8.16/GJ between March and August 2021, reflecting an increase of 12%. Although average retailer prices remained higher than average prices offered by producers, the highest price offered by retailers ($9.61/GJ) only narrowly exceeded the highest price offered by producers ($9.42/GJ) between March and August 2021. Several factors may have contributed to this premium, including retail margins, transportation costs and buyers' willingness to pay for additional flexibility in non-price terms and conditions.

Despite an increase in offers made by producers and retailers from mid-2021, users have reported difficulties in obtaining suitable offers for gas supply, primarily for supply from 2023 onwards (chapter 5). We will continue to closely monitor the offers suppliers are making to the market, and the ability of buyers to secure gas, in our next interim report.

### 4.4.2. Offers in Queensland did not rise in line with LNG netback prices following a significant increase in LNG prices

Chart 4.6 compares offers made by producers for supply in Queensland in 2022 between 1 January 2020 and 12 August 2021 (as at the time the offer was made).

**Chart 4.6: Gas commodity prices (2022$/GJ) offered by producers to all buyers for 2022 supply against expectations of LNG netback (Queensland)**

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

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.
Expected 2022 LNG netback prices increased steeply during 2021, with LNG netback prices in August over $14/GJ and more than double those expected in January, on average. This was driven by price increases in global LNG futures markets, with forecasts of a global LNG supply shortage in early 2022 growing over the period (section 4.3).

From March to August 2021, the expected LNG netback price exceeded the price of the majority of offers for supply in Queensland during 2022. This was despite offer prices increasing from approximately $6.7/GJ to $8.4/GJ during the period, with the growth in expected LNG netback prices outpacing the growth in prices offered.

Expected 2022 LNG netback prices were approximately $6/GJ above quantity-weighted average prices offered in August 2021, with expected LNG netback prices significantly above prices offered for the first time since the Inquiry began.

Several factors may have contributed to the divergence between domestic and LNG netback prices. For example, as noted in section 4.3, expectations of oil prices have been much more stable than those for JKM, with 2022 JKM futures doubling over February to August 2021 and Brent futures increasing by around 20 per cent. To the extent suppliers have had regard to oil-linked LNG prices when determining LNG netback prices, this may have resulted in more stable domestic offers.\footnote{In our review of supplier pricing strategies, we found that oil prices have had a key influence on domestic pricing, and that this was part of the reason for the disparity between domestic and LNG netback prices over 2019 and 2020. It also appears that domestic offers in 2021 have aligned with oil-based netback prices more than JKM netback prices.}

In addition, as we found in our review of supplier pricing strategies, some suppliers appear to have been influenced in their domestic pricing by the perceived threat of regulatory intervention at prices around $10/GJ or above. This may also have contributed to domestic offers having remained below $10/GJ over 2021 despite significant increases in LNG prices, particularly given current policy developments in the gas industry.

Domestic market dynamics also influence pricing outcomes in the domestic market. We also found that the low prices offered in 2020 were influenced by the large drop in LNG and oil prices, unexpected increases in domestic supply, and the need for suppliers to meet lower domestic market prices. While this dynamic has since shifted, domestic price offers appear to have been slower to adjust.

We note, as shown above, there were also relatively few offers in Queensland following the significant increase in LNG netback prices in mid-2021. The pricing information available to the ACCC since this time is therefore limited.

**4.4.3. Prices offered in the southern states trended toward seller alternative levels in mid-2021**

Chart 4.7 compares offers by producers and retailers in the southern states for 2022 supply made between 1 January 2020 and 16 August 2021 with:

- expectations of 2022 LNG netback, and the buyer and seller alternative prices, as at the time the offer was made, and
- the estimated forward costs of production for marginal gas production in the southern states.

As noted in previous reports, prices in the southern states in a well-functioning market are expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user’s location, and
• the seller alternative (representing a floor in negotiations) – the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production

**Chart 4.7:** Gas commodity prices (2022$/GJ) offered by producers to all buyers, and retailers to C&I users for 2022 supply against expectations of LNG netback (southern states)

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

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

Offers to the southern states for 2022 supply grew more dispersed over 2021, clustering around $8/GJ in March and widening to a range between $7.20/GJ and $9.60/GJ towards the middle of year. As in Queensland, prices offered did not rise in line with the steep increase in expected 2022 LNG netback prices during 2021.

Between March and August 2021, 145 offers to the east coast were priced below the expected LNG netback level with 74% for a supply term of two years or less. By comparison, only 8 offers fell below the expected LNG netback price during the corresponding period in 2020.

Over this period, offers to the southern states trended toward the seller alternative price, clustering around this level in June and July 2021 for the first time since we began the Inquiry, despite a forecast shortage in the southern states for 2022 (see chapter 1).

In June 2021, the seller alternative grew above the estimated forward cost of production, reaching $10.36/GJ in August 2021. While some early-August offers were priced below the seller alternative, there is insufficient data to conclude whether prices offered rose to the seller alternative during the remainder of August.

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156 We measure the forward cost of marginal gas production in the southern states using the estimated forward cost of production in the Sole field, located in the Gippsland Basin (see Appendix B).
As in Queensland, the drivers of the divergence between domestic offers and LNG netback prices in mid-2021 are unclear. Relatively stable expected oil-linked LNG netback prices amid volatility in JKM futures markets, the divergence in Queensland, and concerns over regulatory intervention may have contributed to this dynamic, but these effects cannot be disentangled.

4.5. Prices payable for supply in 2022 have increased on both a fixed cost and commodity linked basis

We continue to report on the prices payable under GSAs to provide an indication of the price medium to large gas buyers and suppliers on the east coast are expected to pay and receive under contracts for supply in the short to medium-term. Additionally, we report on the average take-or-pay multiplier and load factor to provide an indication of the levels of volume flexibility which have been agreed to.

This section analyses prices payable and volume flexibility under GSAs for supply in 2022 that were entered into between 1 January 2020 and 12 August 2021.

GSAs in this analysis:

- are entered into by producers with all buyers, or by retailers with C&I users and gas-powered generators.
- have fixed prices or prices linked to a commodity price index, such as Brent Crude oil.
- have an ACQ of at least 0.5 PJ and a term of at least 12 months.

We estimate prices under GSAs using assumptions relating to a number of variables, including the AUD/USD exchange rate, the consumer price index, and the price of oil and LNG on international spot markets. However, while bids and offers are priced using expectations of these variables at the time the bid of offer was made, GSA prices payable are estimated based on current market expectations for the relevant supply year.

4.5.1. Prices payable for supply in 2022

Chart 4.8 presents quantity-weighted average wholesale gas prices expected to be paid under all GSAs entered into by producers and retailers for delivery in the east coast gas market in 2022. Chart 4.8.A repeats this analysis, however it excludes commodity linked prices.

The left-hand side of both charts compares average prices payable under GSAs entered into by producers and retailers in the southern states over three periods:

- January to August 2020.
- September 2020 to February 2021.
- March to August 2021.

The right-hand side of both charts aggregates this information over January 2020 to August 2021, in addition to presenting the prices payable under GSAs entered into by producers for delivery in Queensland.

Prices agreed by producers for delivery in the southern states in 2022 averaged $8.56/GJ between March and August 2021, down by around 5.7% from GSAs executed between September 2020 and February 2021. Comparing the same two periods, average prices agreed by retailers in the southern states increased by around 17.9% to $8.22/GJ.

As noted above, we have found that oil prices have been a key factor influencing domestic gas pricing in recent years, including directly in price mechanisms of executed GSAs and as
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part of LNG netback price calculations used by suppliers for domestic pricing. In our analysis
of domestic GSAs, we have observed that several oil-linked GSAs for 2022 supply have
been executed since January 2020.

Comparing the average producer prices between chart 4.8 and chart 4.8.A demonstrates the
effect of oil-linked contracts on average producer prices in the southern states. Oil price
expectations for 2022 increased over the reporting period, as noted in section 4.3, increasing
prices payable under already agreed oil-linked GSAs. The difference between average
prices was the result of a small number of oil linked contracts in each period with high
contracted quantities of gas compared to fixed cost producer contracts. A relatively high
volume of gas was contracted through GSAs linked to oil between September 2020 and
February 2021, resulting in a particularly large difference of $2.72/GJ between these two
averages. The decline in this difference in the March to August 2021 period reflects, in part,
a higher proportion of gas being contracted under relatively cheaper (at this point in time)
fixed price GSAs.

The right-hand side of both charts highlights that Queensland producers only entered fixed
priced contracts and have lower payable prices compared to the southern states at
$6.97/GJ.

Prices payable for GSAs entered into with retailers for delivery in the southern states were
the same in both charts as retailers also only entered into fixed price GSAs. The aggregated
retailer average price of $7.45/GJ suggest buyers of these GSAs, which includes the
majority of C&I users, were relatively protected from increases in commodity prices during
the period.
Chart 4.8: Expected gas commodity prices (2022 $/GJ) payable under GSAs entered into in the east coast gas market for 2022

Source: ACCC analysis of information provided by suppliers.

Note: Expected prices payable under GSAs executed by retailers in Queensland were excluded from chart 4.8 because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.

Chart 4.8.A: Expected gas commodity prices (2022 $/GJ) payable under GSAs entered into in the east coast gas market for 2022 supply excluding commodity-linked prices

Source: ACCC analysis of information provided by suppliers.

Note: Expected prices payable under GSAs executed by retailers in Queensland were excluded from chart 4.8.A because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.
4.5.2. Flexibility under GSAs for supply in 2022

This section reports on quantity-weighted average take-or-pay multipliers and load factors in GSAs. The take-or-pay multiplier and the load factor are key terms and conditions in GSAs that, in practice, provide buyers with flexibility in how they manage their gas usage.

Chart 4.9 shows average take-or-pay multipliers and load factors under GSAs for supply in 2022 which were executed between January 2020 and August 2021.

Chart 4.9: Average load factor and take-or-pay multiplier under GSAs entered into in the east coast gas market for 2022 supply

<table>
<thead>
<tr>
<th>Take-or-pay multiplier</th>
<th>Load factor</th>
<th>Take-or-pay multiplier</th>
<th>Load factor</th>
<th>Take-or-pay multiplier</th>
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<td></td>
<td>1.31</td>
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</tr>
</tbody>
</table>

Source: ACCC analysis of information provided by suppliers.

Note: Average take-or-pay multipliers and load factors under GSAs executed by retailers in Queensland were excluded from chart 4.9 because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.

The overall picture remains little changed since the July 2021 interim report. GSAs executed by retailers for supply in the southern states provide more flexibility on average than those executed by producers for supply in the southern states and in Queensland.

The differences in the level of flexibility offered under the different categories of GSA in chart 4.9 may be driven by the capability of sellers and requirements of buyers. Retailers may be in a better position to provide flexibility in GSAs to C&I gas users, as they can manage changes in the demand for gas on a portfolio basis and may also have access to underground or pipeline storage to manage variations. The majority of retailer GSAs had a take-or-pay multiplier of 80% while the majority of producer GSAs had a take-or-pay multiplier of 90%.

The average take-or-pay multiplier for producers and retailers in southern states were broadly similar because the producer average was driven by a small number of significantly large GSAs with take-or-pay multipliers of around 80%. The average take-or-pay multiplier under producer GSAs for delivery in Queensland was significantly higher, at 91%.

The average load factor was roughly equivalent under producer GSAs for delivery in Queensland and the southern states. It was significantly higher under retailer GSAs for delivery in the southern states, at 1.31. Further, while the majority of producer GSAs for
supply in 2022 had a load factor of 1.02, load factors agreed under retailer GSAs were much more varied.

The relative lack of change in the level of flexibility provided for in executed GSAs contrasts with reports from C&I users that it is becoming more difficult to negotiate with gas providers on flexibility in contract terms (chapter 5). This may be a result of C&I users choosing not to finalise agreements with sellers who are unable or unwilling to offer the level of flexibility that they require.

4.6. Some LNG producers continue to provide insufficient evidence of compliance with the Heads of Agreement

Under the current Heads of Agreement (HOA) between LNG exporters and the Australian Government, LNG exporters have committed to provide the ACCC with material which can be used to assess their compliance with the HOA.

Under the HOA exporters have committed to not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market.

The LNG exporters have also committed that prices offered to domestic gas users will be internationally competitive, and that:

- spot prices offered to the domestic market will have regard to the spot price LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets.
- term prices offered to the domestic market will have regard to forward term prices LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets.

In our July 2021 report we observed that some of the LNG exporters had not clearly demonstrated compliance with the agreement and that we expected them to significantly improve the evidence they provide to substantiate compliance in future.

We amended our information notices to expand our ability to scrutinise the LNG producers’ compliance with the HOA. LNG producers have improved their documentation of offers made to the domestic market for exported uncontracted gas since our last interim report. However, we remain concerned about how some LNG producers have approached demonstrating compliance with the HOA.

In particular:

- that some gas originally offered in some EOI processes was not ultimately able to be supplied to domestic customers and whether reasonable notice was provided.
- while some domestic offers have been below export parity prices more recently, many domestic offers from some LNG producers do not appear to have been internationally competitive. Some LNG producers have also provided insufficient information regarding their consideration of LNG prices when making domestic offers.

We are also concerned about an exporter principally relying on short term offers made to the Wallumbilla Gas Supply Hub (GSH), in addition to some historical longer term offers. While likely compliant with the Heads of Agreement, this form of market engagement may not meet the needs of many domestic buyers who require long-term agreements to be locked in well ahead of gas supply. This LNG producer has told the ACCC that it intends to engage with the domestic market using other additional means.
4.6.1. LNG producer offers to the domestic market

LNG producers have generally provided better documentation to substantiate domestic offers made for exported uncontracted gas. For example, some have provided more comprehensive accounting of the offers that are considered to demonstrate that gas was offered domestically before being exported. One LNG producer has also improved its reporting of the methodology and inputs used to calculate LNG netback prices (as discussed below).

For each cargo sold to the international market between 26 February and 12 August 2021, LNG exporters were required to provide the ACCC with evidence that gas volumes were first offered to the domestic market.

Between 26 February and 12 August 2021, the east coast LNG producers sold 3 spot or additional LNG cargoes to the international market, totalling around 12 PJ. This is lower than the 14 spot cargoes (totalling 53 PJ) sold between 1 September 2020 and 26 February 2021 as discussed in our July 2021 report. Historical spot sale information from LNG producers shows that LNG spot sales are typically lower around the middle of the calendar year and increase towards the end of the year.

Between 26 February and 12 August 2021, the east coast LNG exporters made offers to the domestic market totalling 94 PJ for supply in 2021, in addition to previous offers for supply in 2021. This is well in excess of the 12 PJ that was exported as LNG spot sales over this period, although as discussed below we have some doubts about whether some gas originally offered in some EOI processes was ultimately able to be supplied to domestic customers. As of 12 August 2021, the total volume of offers accepted over this period was 16.3 PJ.

However, while LNG producers have improved their documentation, we consider that information provided by some exporters still does not sufficiently demonstrate compliance with some of the HOA commitments.

Domestic EOI processes

We have assessed the information provided by LNG producers against their commitments under the HOA to offer gas to the domestic market. We have analysed this information and other data provided by LNG producers on their interactions with domestic buyers to determine whether they have made genuine offers to supply gas domestically before making offers to the international market. However, it is unclear whether some gas originally offered in some EOI processes was ultimately able to be supplied to domestic customers.

One of the LNG exporters cited an EOI process to demonstrate that it had offered exported gas to the domestic market. The EOI invited a range of domestic buyers (including retailers, C&I and GPG) to bid for a significant quantity of gas.

While the EOI was issued to a range of potential domestic buyers and offered gas volumes well in excess of the LNG that was exported, we are concerned that the gas was not offered to the domestic market with reasonable notice. While the LNG producer has told the ACCC that it had already offered this gas to the domestic market prior to this EOI process, the EOI was issued less than one month before the gas was offered to the LNG market, and domestic gas supply was to start less than two weeks after the due date for responses to the EOI. Some domestic gas buyers, particularly C&I users, may not be able to accept large volumes of gas on such short notice.

Further, only one buyer bid into this EOI process, and at a price significantly below the ACCC’s LNG netback price at the time. However, the LNG producer rejected this bid without making a counter-offer. The LNG producer told the ACCC that it followed up verbally with the...
buyer after receiving the bid and informed the buyer that it would not make a counter-offer. However, we would expect to see LNG producers make counter-offers to potential buyers that bid into a process in which they have been invited to do so.

Another EOI process was cited by an LNG exporter to demonstrate compliance with the HOA. The EOI invited a range of domestic buyers (including retailers, C&I and GPG) to bid for a significant quantity of gas. Further, the EOI was issued more than 6 months before the gas was offered to the LNG market and more than 3 months before the start of proposed domestic gas supply.

This EOI was also used by the exporter to demonstrate compliance with the HOA in respect of LNG spot cargoes sold earlier in 2021. The exporter used the same domestic offers to demonstrate compliance in relation to new LNG spot sales. While the ACCC considers that it can be appropriate to use offers (in this case, simultaneous offers to multiple potential buyers under an EOI) more than once to demonstrate compliance with the HOA, this depends on the gas volumes exported and how they compare to the volumes offered domestically.

While there were significant volumes of gas offered under this EOI – well in excess of the LNG volumes exported – which were available to potential buyers at the time of the offer, due to a change in circumstances the LNG exporter was not ultimately able to supply all of the gas that was originally offered domestically. The exporter received bids from around a third of potential buyers. Of the buyers that did express interest, subsequent negotiations did not result in gas supply and most bids were rejected. Further, in one negotiation with a major domestic supplier, the LNG exporter ultimately informed the buyer that it was no longer able to provide firm gas supply over the period initially offered. This EOI process did not result in any GSAs.

As noted in the July 2021 report, we do not consider that domestic offers made for gas that an exporter is unable to supply is sufficient for demonstrating compliance with the Heads of Agreement.

**Short term domestic offers**

The ACCC considers that offering gas into the GSH and other short-term domestic markets can be an effective way for LNG producers to offer and supply gas to domestic buyers, particularly when complemented with other forms of market participation such as through the issuing of and participation in EOIs and direct bilateral engagement.

However, GSH offers may not meet the needs of many domestic buyers who require long-term agreements to be locked in well ahead of gas supply. Not all domestic buyers are able to take large quantities of gas on short notice from the GSH, therefore this approach to domestic supply may favour gas buyers with large flexible portfolios. Further, significant quantities of gas could be purchased from the GSH by other LNG exporters, in which case the gas may be exported rather than used to supply the domestic market. LNG producers themselves may also purchase gas on the GSH, in which case only their net sales to the GSH should be considered.

One exporter has principally relied on offers to the Wallumbilla Gas Supply Hub (GSH) to demonstrate compliance with the Heads of Agreement, in addition to some historical longer term offers. This exporter cited offers it made to the GSH over 2021 leading up to when it offered gas to the LNG market, with the total volume of gas offered well in excess of the gas that was exported. However, most offers were, by their nature, to be supplied the day of the offer or in the following days. Further, many offers cited were in the days and weeks immediately before gas was offered to the LNG market.
One LNG producer also cited short term offers made to another LNG producer to demonstrate compliance with the HOA. Unless LNG producers can show otherwise, the ACCC does not consider that gas offered by exporters to each other represents an offer to the domestic market, as it is unclear whether this gas will be consumed domestically or whether it would be exported.

Further, one LNG producer has cited many verbal short term offers that were made to domestic buyers and brokers. While we acknowledge that verbal offers may be a common feature of developing liquidity in short term markets, as we noted in the July 2021 report, references to verbal offers do not provide the ACCC with verifiable evidence to substantiate compliance, given we are unable to confirm their accuracy.

4.6.2. International competitiveness of domestic offers

As discussed above, under the HOA the LNG exporters have committed to offering internationally competitive prices to the domestic market, and that they will have regard to spot and term LNG prices as relevant when making domestic offers.

While some domestic offers in the east coast gas market have been below export parity prices more recently (section 4.4.3), most of the long-term offers (and many of the short-term offers) made by LNG producers over 2020-21 for 2021 supply have been priced significantly above comparable LNG netback prices. While the Heads of Agreement does not expressly require prices to align with LNG netback prices, these offers do not appear to have been internationally competitive or made on competitive market terms.

We also note that most LNG producers have not indicated quantitatively how domestic long-term offer prices have accounted for the cost of providing non-price terms and conditions. One exporter said that it does not calculate the cost of non-price terms when calculating offer prices. This is consistent with the finding in our review of supplier pricing strategies that the non-price terms typically sought by gas users do not appear to attract a significant premium relative to underlying commodity gas prices. It also supports our finding that the costs of providing flexibility in GSAs are generally not used in practice by suppliers when making offers.

LNG producers made a limited number of long-term offers to the domestic market over 2020–21 for 2021 supply that include an indication of price. Part of the reason for this may be that, as noted above, one LNG producer's domestic market activity has mostly involved making short-term offers into the Wallumbilla GSH. Further, another LNG producer's EOI processes have received very few bids, and for the bids that were received, the exporter in many cases did not make a counter-offer.

Of the long-term domestic offers that were made by LNG producers for 2021 supply since the start of 2020, most have been priced significantly above the ACCC's LNG netback price at the time of the offer. In Queensland, some long-term offers in 2020 were made at around the LNG netback price, but most were made well above netback. In southern states, most offers made by LNG producers have been at or above Victorian buyer alternative prices.

Short-term domestic offers made by LNG producers have broadly aligned with Wallumbilla GSH traded prices and have generally been around or below month-ahead JKM netback prices. However, some short-term offers have exceeded JKM netback prices by significant amounts. For example, in July 2021 an LNG producer made a range of offers into the GSH up to around $20/GJ when JKM netback prices were between $13–16/GJ.

4.6.3. LNG producer consideration of LNG prices

We have also assessed the extent to which LNG producers have demonstrated their regard to spot or term LNG prices when making domestic offers. LNG producers have improved
their reporting in this respect, indicating which LNG prices were considered for most offers made after the signing of the January 2021 HOA. However, some of the offers cited by some LNG producers to demonstrate compliance with the January 2021 HOA do not indicate whether or how LNG prices were taken into account. (We note, however, that many of these offers were made before the signing of the January 2021 HOA when the requirement to have regard to LNG prices was not yet in place).

For example, as noted above, the EOI processes one LNG producer cited for HOA purposes received very few bids. For many offers that were made that indicated a price, the LNG producer did not indicate if or how it had regard to LNG prices in determining the offer price. This exporter indicated that, for domestic offers more broadly, it generally did not have regard to LNG prices. For some offers, the exporter instead considered other factors such as its portfolio position and internal domestic market assessments, particularly in cases where LNG production capacity was constrained.

In contrast, another LNG producer indicated that, for almost all of its short term domestic offers, it had either considered Asian LNG spot prices or noted that the gas was sold to manage LNG plant interruptions. This exporter provided sufficient explanation for how it had regard to LNG spot prices, while also detailing the methodologies and values it used for calculating netback prices in the context of each domestic offer. This exporter also referred to several offers made prior to the signing of the January 2021 HOA, for which it did not specify whether it had regard to LNG prices, including longer term offers made to retailers and C&I users.

Under the current HOA, the ACCC expects LNG producers to indicate, for every domestic offer, if and how it had regard to either LNG spot or term prices when determining the offer price. When LNG producers have not had regard to LNG prices, we expect them to clearly explain why.
5. Commercial and Industrial (C&I) user experience

5.1. Key Points

- Primary concerns of C&I users continue to be long term supply uncertainty and gas prices, with more users expressing concerns about the availability of gas compared to the last survey.

- C&I users report that there has been a change in market conditions since June 2021, with reduced availability of gas and increased prices offered for supply in 2022. Users indicated that some suppliers are switching their pricing methodologies to reflect the highest price marker available, rescinding offers without explanation, and are unwilling to negotiate flexibility in contract terms.

- Users reported receiving limited offers, or having limited confidence in receiving offers, that meet their specifications for 2023 supply and expect further tightening of supply and higher gas prices. In November 2021, Incitec Pivot Limited (IPL) announced it will cease manufacturing at its Brisbane-based Gibson Island plant at the end of 2022, as it had been unable to secure an affordable gas supply from 2023 onwards.\(^{157}\)

- The facilitated markets experienced relatively high prices in July 2021 and some users were exposed to these prices to differing degrees. Several users expect volatility in facilitated markets to persist given concerns around availability of gas and are seeking to reduce their exposure through firm contracts.

- Direct engagement or user-led tenders are strongly preferred by users over supplier-initiated EOI processes, driven by the desire to align contract terms with investment decisions. Smaller users continue to utilise third party intermediaries or buyers’ groups to obtain gas offers.

5.2. Introduction

The ACCC approached 64 C&I gas users to participate in a survey or to provide input on their recent experiences in the east coast gas market. Fifteen C&I users responded to the survey and three additional respondents met with the ACCC to discuss their experiences. These users have a total demand of approximately 102 PJ/a, and account for approximately 40% of forecast industrial demand. Two of the survey respondents are smaller users (demand less than 500 TJ), and the remaining thirteen have demand at or greater than 500 TJ.

The views reported in this chapter reflect information provided by the sample of C&I users that responded to our survey or otherwise met with the ACCC in August and September 2021.

5.3. C&I users report reduced availability of gas, increased prices offered and changes in supplier behaviour since June 2021

5.3.1. Long term supply uncertainty and gas prices remain users’ primary concerns

Primary concerns of C&I users continue to be long term supply uncertainty and gas prices. Compared to our survey in March 2021, an increased number of users ranked availability of

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gas as a more concerning issue in the September 2021 survey, overtaking transport prices as the third most concerning issue.

Nine of 15 respondents ranked long term uncertainty surrounding the gas market as the most or equal most concerning issue. Gas prices were the second biggest concern. See chart 5.1 which outlines users’ primary concerns.

Some users continue to report challenges with transport charges and report limited engagement or opportunity to negotiate with pipeline operators. This is consistent with concerns raised with the Inquiry by non-C&I shippers, see section 6.10 for further information.

Chart 5.1: C&I users' rating of concerns in the east coast gas market

Source: ACCC Gas inquiry C&I user survey September 2021.

The July 2021 interim report observed that short-term prices had moderated but there had been limited engagement from suppliers early in 2021. Users report that market conditions have changed since June 2021, with offered prices increasing, difficulty experienced in attaining suitable offers and changes in supplier behaviour. This includes suppliers frequently switching pricing methodology, making offers that are not suited to users' specifications and withdrawing offers before the deadline.

Users are concerned about reduced availability of gas supply and, since June 2021, higher priced offers. For supply in 2022, users reported receiving offers with prices ranging between $7.50-9.90/GJ. This is broadly consistent with our findings in section 4.4.

We noted in July 2021 that users had reported short term offers for terms of up to 12 months were available between $6.80 and $9.15/GJ, with most prices around $7/GJ. However, a number of users in the market after June 2021 experienced substantially higher prices for

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2021-2022 supply years. Between March to November 2021 there has been a notable increase in offer prices reported by users to the Inquiry. Users reported prices ranging between approximately $9-10.10/GJ for 2023 and $9-10.25/GJ for 2024 supply years.\footnote{These price ranges only include offers for 2023 or 2024 supply reported to the ACCC by users. Some users may have received prices outside of this range.}

One user noted that suppliers are no longer pricing their offers in a consistent manner to previous years. That is, suppliers' justification for offered prices frequently changed between reflecting facilitated market prices to being oil or JKM linked. This user suggested that suppliers seem to be justifying prices based on the highest price marker at any given time. This sort of behaviour can undermine users faith in the negotiation process and lead to a 'lack of confidence in the validity and sincerity of offers received'. The frequent switching of pricing methodologies further reinforces the ACCC's previous observations that suppliers may face limited competitive constraints in determining their prices.

5.3.2. **Users continue to face difficulties receiving offers and contracting for supply beyond 2022**

Chart 5.2 outlines the weighted average proportion of demand (users' gas load) reported by users as being contracted under firm GSAs from 2021 to at least 2024. The values in chart 5.2 are only reflective of the users that responded to the survey, which differs over time. We note that some differences between our March and September 2021 survey results, particularly the decrease in contracted demand in the 2021 supply year, are due to changes in respondents and users taking up contracts with partial fixed and floating arrangements. This chart does not reflect gas that is obtained by users through the facilitated markets. While some users can obtain gas through the facilitated markets, most users do not exclusively rely on gas from facilitated markets.

While the majority of users have contracted gas to meet their needs for 2022, this is not the case for 2023 supply. There remains a 28% difference in the weighted average proportion of demand under firm contracts for gas between 2022 and 2023. Despite being six months closer to the 2023 supply year, the proportion of demand secured by users between 2022 and 2023 has not narrowed compared to our July 2021 interim report (which we would expect to happen).
Consistent with our last report, a number of users continue to face challenges receiving suitable offers for supply from 2023 and beyond. User comments about these challenges include:

- one user received an offer from a producer for a volume considerably higher than the user's requirements.
- a user that recently ran a tender process commented that they 'disappointingly [did not receive] a single compliant response…that is, the full volume for full term regardless of price'.
- another user advised that 'there is little liquidity in the market' for supply in 2023 and beyond, and despite anticipating more challenges than previous years due to tightening international market conditions, they were 'alarmed by the number of producers and retailers that have declined to make an offer to supply gas for 2023 and 2024'.

Users expect further tightening of supply and associated price increases particularly from 2023. This tightening of supply and price increases are already significantly impacting some users business operations. Incitec Pivot Limited, a large user, announced it will cease manufacturing at its Gibson Island plant at the end of 2022, noting that 'despite significant

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160 We have changed our methodology for the September 2021 values to only include firm contracted demand. This is to distinguish between users who procure gas for all or part of their load from facilitated markets through retailer contracts. For hybrid contracts, the portion under firm contracts is captured in this graph.
efforts over recent months [they] have been unable to secure affordable gas supply beyond the end of [their] current gas contract.  

Some users report that they have been unable to obtain offers for supply in 2023 and beyond. Consistent with rising international prices and concerns the Inquiry has previously reported on suppliers delaying contracting, some users suggested that producers are waiting to see how high gas prices will climb before offering to sell gas. Users report some suppliers have indicated they would rather leave the gas in the ground or that there is limited gas availability due to insufficient production. A respondent commented that for the first time 'a number of retailers [were] unable to make an offer due to not having sufficient contracted gas on their books'.

One user noted that they are prioritising short term offers and are not currently seeking 2023 supply on the basis that they do not believe they will obtain suitable 2023 offers from suppliers.

While some users noted supply from LNG import terminals could increase gas availability in southern states, concerns remain around the pricing of that gas, as we have previously noted in the course of the Inquiry.

In addition, users report a further shift in supplier attitudes, reflecting a tightening supply environment. Several users noted that since June 2021, a number of suppliers rescinded their offers before the response deadline when facilitated market prices peaked. Limited detail was provided by suppliers on the reasons for withdrawing offers. One user noted that they observed similar behaviour in 2019, where suppliers were withdrawing offers before the deadline and returning with a higher priced offer. This type of behaviour undermines users' confidence in securing gas.

Some users also report that supplier's willingness to offer gas and negotiate has reduced. One user noted that since mid-2020 there has been 'decreased proactive approaches from gas suppliers'. Another user advised that providing offers to the domestic market is not a priority for suppliers, and that they are doing the 'bare minimum just to tick boxes'. Users continue to report that non-price terms and conditions in GSAs do not appropriately balance the risks between parties, with users bearing the most risk. Several users indicated that contract terms and conditions are not in the buyer's favour compared to other commercial agreements. Given concerns around availability of gas and increasing prices, some users said they do not have the required bargaining power in negotiations to amend non-price terms and conditions. One user observed that 'they are forced to take all the risk and that the gas consumer has no recourse for loss or injury'.

Users did not report contracts being secured through any supplier-led EOI processes between the second and third quarters in 2021. One user noted that some suppliers have delayed EOI processes, indicating they will run EOIs in August 2022 instead. A justification provided for the delay was that producers need to receive engineering clarification to ascertain the marginal volumes of gas available for sale. This user also experienced a large producer running an initial EOI process for a small number of buyers. The user noted that they were informed that they had to wait until the initial EOI process had finished before they would be invited to engage in another EOI process.

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5.4. Some users expect facilitated market conditions to continue to be volatile and are actively reducing their exposure

Our July 2021 interim report found that medium to large users were increasingly utilising, or considering using, facilitated gas markets to provide them with flexibility in managing demand variability and to minimise their costs. Some gas suppliers were providing more complex products, often with more exposure to facilitated markets and some users were willing to take on this additional exposure.

Users with greater exposure to the facilitated markets incurred high price increases in June to July 2021. There were extremely high fluctuations in July 2021 in the facilitated markets, particularly in the Sydney and Adelaide STTMs, and the Victorian DWGM. Daily prices increased to very high levels in the week commencing 4 July, particularly in southern regions, sitting around $24-35/GJ on individual days in Sydney, Adelaide, and Victoria from 7 July. According to the AER Gas Market Report, on 7 July, the price variation was $8.56/GJ in Sydney STTM and $8/GJ in Adelaide STTM.\textsuperscript{163} Daily high prices were the result of factors including shortages due to coal plant outages nationwide and gas storage levels running at low levels.

Users that signed up to 100% spot contracts were entirely exposed to the high STTM prices [$24-35/GJ] in July. This demonstrates the difficulties and risks experienced by users when trying to explore different options to source supply. Greater participation in facilitated markets can result in lower prices but can also expose users to significant price risk. Being able to appropriately balance potential risks and benefits can be difficult for small-medium users, particularly given their bargaining power and supply options are often limited.

Some users expect these volatile conditions to persist, given concerns around gas availability and high international LNG prices. Two users noted that the gas market has higher volatility than the electricity market, creating greater uncertainty.

In response to high prices in July 2021, several users are looking to enter fixed price contracts to reduce their exposure to price volatility. For example, one user that procures gas from facilitated markets commented that 'with the price and market volatility—we have reverted to using a broker [to source firm gas contracts]'..

Another user that expects continued volatility is looking to 'get out of spot markets and only use it at the margin'. This user commented that for them 'there is no real value in remaining unhedged'.

A smaller user that does not engage in the facilitated markets noted that they do not engage in the facilitated markets because there is too much price uncertainty which 'makes budgeting impossible'.

Conversely, another user suggested the drivers for high prices in July may be temporary and that potential savings remain when compared to fixed priced contracts:

\begin{quote}
Before June our overall delivered gas price was approximately 30% cheaper per GJ than under our previous contract. Taking into account the high prices in June and July we are still averaging 17% cheaper per GJ on the cost-plus spot gas arrangement than our previous fixed forward contract.
\end{quote}

It is important to acknowledge the difference between short term market dynamics leading to a higher priced environment and persistent volatility, which impacts on users' decision-making. The volatility associated with spot market prices, including in the facilitated markets

\textsuperscript{163} AER, AER Gas Market Report, 4-10 July 2021, accessed 30 September 2021.
and the JKM, can make it difficult for users to make investment decisions based on spot-linked contracts. One user indicated that JKM–linked contracts present a challenge for domestic users:

*Price volatility and the forward curve ending in 2023 means users cannot get assurance of gas costs, which is a critical part of their investment decision making process.*

Concerns remain about the inability to hedge, as there are minimal hedging products available to reduce exposure to high price events. One large user cited challenges from physical constraints due to plant and storage outages and pipeline constraints, noting 'managing volatility risk becomes difficult when physical tools are unavailable to increase gas supply into markets to cover any spot exposure'.

One user who previously reported using caps and swaps to hedge their risk and reduce transport costs indicated there is now reduced access to swaps in southern markets.

**5.5. Large users overwhelmingly prefer seeking gas through direct engagement with suppliers, while smaller users often utilise third party intermediaries**

Users that responded to our survey overwhelmingly prefer seeking gas through direct engagement or user-led tenders. This is because supplier-led EOI processes often do not match users' business requirements or align with the required timing of supply. One user indicated that some producers advised they will run their EOI processes in August 2022, but this did not suit the user's supply timing requirements. Another respondent noted that it does not participate in tender processes initiated by producers, commenting that 'invariably, the timing of supply doesn’t suit'. The same user also indicated that it has limited bargaining power and determining when it approaches the market is one of the only ways it can exercise control over its gas arrangements.

While suppliers can use EOI processes as price discovery exercises, one user indicated that they can also be an opportunity for users' price discovery. This user indicated that participating in these EOI processes can provide an indication of others' willingness to pay, as an unsuccessful bid provides feedback that the price in the market exceeded the price they were willing to bid.

All small to medium users (<1PJ) that responded to our survey engage in the gas market through a broker, buyers group or other third-party intermediary. Users report that these third-party intermediaries utilise a range of pricing models. This includes fixed fee payment per contract (some have additional charges for each additional contract year) charged to either the supplier or user, or a percentage of gas cost plus a fixed one-off fee. The latter may also include performance incentives for savings compared to facilitated market prices.

Consistent with our findings in the July 2021 interim report, users are increasingly accessing varying sources of information to form pricing expectations and navigate offers in the market. Chart 5.3 shows the information sources respondents use to form a view on gas prices.

More users listed the ACCC’s LNG netback price and reports as an information source than in the July 2021 report. This may reflect increased awareness and understanding of the LNG netback price series following the completion of our LNG Netback Pricing Review in September 2021. Further, for the first time, two users listed JKM prices as an information source (independently from the LNG netback price series to which JKM is an input).
5.6. Some users are concerned that climate policy uncertainty will increasingly impact gas availability and costs

Some users cited concerns about a lack of cohesive government policy and support on an energy transition away from fossil fuels. These users believe this policy uncertainty and lack of support will increasingly impact the gas market. Respondents outlined concerns around future government policy to achieve net zero emission targets exacerbating existing issues with business costs and gas availability.

There is particular concern about the business investment costs required and whether this would put businesses at a disadvantage. One user expressed that:

"The inability to forecast the costs [required to purchase carbon offsets] into the business case of new equipment purchases to determine the lifecycle costing differences between gas and other fuels [could mean users are unable to] avoid overcapitalising on gas infrastructure."

Another user expressed similar cost concerns and also commented on the inconsistencies between different states and territories:

"Lack of government cohesive policy on transition to renewables may result in high costs of stranded assets born by large users where technologies are not yet mature enough to fully transition to renewables."

Consistent with our July 2021 report, users continue to consider alternative energy sources such as hydrogen, despite the high costs associated with these options in the short to medium term (see box 1.2 for further information). For example, Incitec Pivot Limited has partnered with Fortescue Future Industries to conduct a feasibility study into industrial-scale
manufacturing of green ammonia conversion from hydrogen at their Gibson Island facility.\textsuperscript{164} We expect more C&I users will consider these alternative energy sources as they become more affordable.

6. Transportation and Storage

6.1. Key Points

- As the long-term supply outlook for southern states worsens, pipelines and storage facilities are likely to play an increasingly prominent role in meeting future demand. The market power of pipeline operators remains a concern, and the monopoly pricing the ACCC first identified in the 2015 Inquiry largely continues.

- Firm prices have generally increased in line with inflation between January 2021 and July 2021, with some exceptions.\(^{165}\) Standing prices published by most pipelines are also mostly unchanged, or have increased in line with inflation.
  - The lowest price paid for firm forward haul services on the Amadeus Gas Pipeline (AGP) fell approximately 26%. The highest prices paid for firm forward haul services on the Roma to Brisbane Pipeline (RBP) western haul increased by 12%, and the highest price paid for firm forward haul services on the Tasmanian Gas Pipeline (TGP) increased by 5.3%.

- Prices paid by shippers for as available and interruptible transport services on most pipelines increased in line with inflation between July 2020 and July 2021, with some exceptions. On some pipelines they are priced at a significant premium to firm services.

- Storage prices at the Iona underground storage facility have remained steady, while prices at the Dandenong LNG storage facility have increased. The lack of competition for storage services affords these facilities considerable market power when setting prices.
  - Fixed prices at the Dandenong LNG storage facility increased by between 8% and 46%, while variable (liquefaction) charges have converged towards the upper end of previously reported maximum prices.

- Capacity has been fully contracted, or close to fully contracted, in the near term on pipelines and compression facilities that are used to transport gas south from Queensland. Shippers relying on non-firm services, including as available/interruptible services and the Day Ahead Auction (DAA) to transport gas to southern states during winter months are likely to experience an increasing risk of interruption. This is particularly the case on the South West Queensland Pipeline (SWQP) and Moomba to Adelaide Pipeline System (MAPS).

- In August and September 2021, the ACCC met with shippers to discuss their recent experiences with transport and storage services and service providers. These shippers continue to raise similar concerns to those that have previously been identified, including high transport prices, limited service flexibility, limited bargaining power and unutilised spare pipeline capacity.

- Upcoming changes to gas pipeline regulation should provide greater price transparency and help shippers make informed decisions when dealing with pipeliners. However:
  - The proposed South Australian derogation from individual price reporting requirements will place users in that state at a comparative disadvantage in negotiations with pipeline operators.
  - Effective monitoring and enforcement of the reforms by the AER will be critical in ensuring they have the intended effect. In June 2021, the AER announced one of its key enforcement and compliance priorities for 2021-22 was to ‘(e)nsure service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations’.

\(^{165}\) Inflation was 3.8% over the twelve months to the June 2021 quarter, and 1.4% over the six months to the June 2021 quarter.
6.2. Introduction

Over the course of the Inquiry the ACCC has reported on a range of matters relating to the supply of, and demand for, gas transport and storage services in the east coast gas market. Using information provided by service providers, we have updated our analysis in this report to include:

- prices payable for firm forward, as available and interruptible haulage services as at July 2021, as well as standing prices published by pipeline operators
- prices payable for park and loan services on major pipelines as at July 2021
- prices payable for use of the Dandenong LNG and Iona underground storage facilities
- shippers’ recent experiences with transport and storage services and service providers
- contracted pipeline capacity to October 2024, and physical flows on key pipelines between July 2020 and June 2021
- a summary of recently announced changes to gas pipeline regulation.

In our next report, we will update our analysis of Gas Transportation Agreements (GTAs) and contract variations executed between February 2021 and February 2022, as well as negotiations for access to key pipelines over the same period.

Box 6.1 outlines the approach we have used when reporting prices.

Box 6.1: Pipeline services and approach to reporting prices

There are several different types of pipeline transportation services:

**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.

**As available transportation service**: A service that allows the transportation of gas subject to the availability of capacity. This service has a lower priority than a firm transportation service.

**Interruptible transportation service**: A service that allows the transportation of gas but where 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, where a pipeline has both types of service, as available transportation services.

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

**Loan service**: A service that allows users to “borrow” gas from a pipeline. In practice this involves withdrawing more gas from a pipeline than what is injected on a particular day.

**Compression service**: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

**Approach to reporting prices**

The prices reported in this section exclude GST and are based on invoices issued under contracts entered into for a term of one month or longer, and reflect the terms and conditions specified in those contracts.

Any percentage changes in price are stated in nominal, rather than real, terms.

**Method used to report pipeline prices**

Prices payable for haulage services are reported only where the price applies to transportation across the full length of the pipeline.
The prices for some firm forward haul services are recovered through a capacity charge only (i.e. $/GJ of Maximum Daily Quantity (MDQ)), while others are recovered through a variable charge ($/GJ), or a combination of the two. In the latter two cases, the prices have been converted to a $/GJ of MDQ measure, assuming a 100% load factor (i.e. assuming the shipper uses all the capacity it has contracted). Where the price charged is specified in several tiers, a single rate is calculated using a weighted average.

The prices payable for as available and interruptible transportation services, and park and loan services have been included even when the quantity supplied in that month is zero. The prices reported for these services therefore represent the prices that would be paid under the shipper’s contracts if the services had been utilised.

The as available and interruptible services category includes APA’s ‘short-term firm’ services, as well as APA’s interruptible service, which is only available when a pipeline is fully contracted. APA’s day-ahead firm and within-day services have not been included in the analysis of contract prices.

Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).

Charges relating to imbalances and overruns are not included in our analysis.

**Method used to report storage prices**

The prices payable for use of the Dandenong LNG and Iona underground storage facilities comprise both a fixed and variable charge. The fixed charge is payable for storage capacity and, although storage services are generally sold under contract terms of a year or more, has been expressed on a dollars per GJ of storage capacity per day basis ($/GJ/day) to enable comparability. The variable charge, on the other hand, is measured on a dollar per GJ basis ($/GJ) and incurred when gas is injected or withdrawn. This charge is used to recover the liquefaction cost at the Dandenong LNG facility and the storage injection and withdrawal charges at the Iona underground storage facility.

**Pricing terminology**

The term ‘maximum price’ is used in this section to refer to the highest price paid by shippers in the relevant period, while the term ‘minimum price’ is used to refer to the lowest price.

The term ‘standing price’ is used to refer to:

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

**Comparator of prices**

The prices payable by shippers for use of pipelines and storage facilities will reflect, among other things, the terms and conditions specified in their transportation and storage agreements and when the prices were agreed. The actual prices payable by shippers to use one of these facilities may therefore differ as a result of differences in capacity commitments (including withdrawal and injection rates for storage), service flexibility (e.g. hourly flexibility, load factor), contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement or will fund an expansion) and whether services are provided across a number of assets.
6.3. Background

Gas transmission pipelines move gas from production fields in the Northern Territory, Queensland, South Australia and Victoria to major demand centres in cities and regional areas. The cost of moving gas along a single pipeline is relatively small when compared to gas commodity prices, however the east coast gas market has become an interconnected network of pipelines and gas often needs to travel through multiple pipelines to move from supply sources to demand centres. This means that these transport costs can quickly add up, particularly if a shipper requires more service flexibility.

Generally, gas pipelines have natural monopoly characteristics. The transportation of gas between two points is usually only possible on one pipeline or chain of pipelines. Where alternative paths can be taken, the alternative route can be very indirect. As such, pipeline operators possess significant market power. In the 2015 Inquiry we observed that a large number of pipeline operators had been engaging in monopoly pricing.166 This was giving rise to higher delivered gas prices and having an adverse effect on economic efficiency (the costs of which are ultimately borne by consumers).

We also found that the lack of publicly available pricing and financial information was hindering the ability of shippers to negotiate effectively with pipeline operators and to readily identify any exercise of market power.

In August 2017, an information disclosure and arbitration framework was introduced to reduce the information asymmetry and imbalance in bargaining power shippers can face when negotiating with non-scheme pipeline operators. This was set out in Chapter 6A of the NGL and Part 23 of the NGR.

In our July 2019 interim report we recommended a range of improvements to ensure Part 23 posed more of a constraint on pipeline operators and to improve the quality, accessibility and reliability of the reported information. Some of these recommendations will be implemented through upcoming reforms to improve gas pipeline regulation (see section 6.10), while others are being progressed by the AER.

Market participants also contract a diverse range of gas storage services to help meet seasonal peak demand in southern states, lower overall supply costs (by taking advantage of variable seasonal commodity pricing) and manage market risks. These services are provided by different storage facilities including large longer-term storage facilities located close to gas fields, small seasonal or peaking storage facilities located close to demand centres, and short-term peaking storage services on gas pipelines.

The Dandenong LNG and Iona underground storage facilities are the only facilities that provide storage services to third parties in the east coast gas market. The Iona and Dandenong storage facilities are aimed at different markets which means they don’t directly compete with each other, nor do they face competition from other operators for similar services. This lack of competition allows each storage facility considerable market power when setting prices for their services.

The relatively steady transportation and storage prices we have seen over the course of the Inquiry reinforce the need for effective and enforced regulation to address monopoly pricing and ensure access to key transport and storage infrastructure.

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166 As noted in the 2015 Inquiry, monopoly pricing is not a contravention of the Competition and Consumer Act 2010 (Cth) (CCA). It is legitimate and expected commercial behaviour. In a market economy where the profit motive drives private enterprise, it is expected that firms which do not face effective competition, or a threat of such competition, will engage in such behaviour. Monopoly pricing can, nevertheless, have a detrimental effect on economic efficiency and consumers.
Figure 6.1: Firm transportation and storage prices as at July 2021

Notes: The transportation and storage prices are based on invoices in July 2021 provided by operators, and exclude GST. Transport and storage prices have been calculated in accordance with the approach described in box 6.1.

* Tariffs include the cost of the nitrogen removal service.
- While this pipeline is a bi-directional pipeline, the prices reported are for northern haul services only.
# The variable charge for the Dandenong LNG storage facility reflects the liquefaction cost.
^ The variable charge for the Iona gas storage facility reflects the charge for injection into the storage facility (I) and withdrawal from the storage facility (W).
% While prices have been expressed on a $/GJ of SC/day basis, the ACCC understands that storage services are generally sold under agreements with contract terms of one year or more and not on a day-to-day or short-term basis.
6.4. Firm forward haul prices have generally increased in line with inflation

Table 6.1 outlines the minimum, maximum and standing prices paid for firm forward haul services in July 2021, and the respective changes between and January 2021 and July 2021. For reference, inflation was 3.8% over the twelve months to the June 2021 quarter and 1.4% over six months to the June 2021 quarter.

Table 6.1: Firm forward haul service prices as at July 2021

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Price ($/GJ as at July 2021)</th>
<th>Price change between January 2021 and July 2021 (%)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
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<tr>
<td>AGP</td>
<td>0.421</td>
<td>0.707</td>
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<tr>
<td>NGP</td>
<td>2.060</td>
<td>2.331</td>
</tr>
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<td>CGP</td>
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<tr>
<td>QGP (to Gladstone)</td>
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</tr>
<tr>
<td>RBP Eastern haul</td>
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</tr>
<tr>
<td>RBP Western haul</td>
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</tr>
<tr>
<td>SWQP Western haul</td>
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<tr>
<td>SWQP Eastern haul</td>
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<td>MAPS Southern haul</td>
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<tr>
<td>PCA (SEAGas)</td>
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<tr>
<td>EGP</td>
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<td>1.332</td>
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<tr>
<td>MSP (Culcairn to Sydney)</td>
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<td>0.434</td>
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<tr>
<td>MSP (Moomba to Sydney)</td>
<td>0.762</td>
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</tr>
<tr>
<td>TGP</td>
<td>1.396</td>
<td>2.660</td>
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</table>

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites.

Note: Pipeline operators escalate their standing prices at the beginning of the calendar year. In addition to this, APA adjusts its prices quarterly in April, July and October. Minimum and maximum prices change frequently based on GTAs that have either commenced, expired or been varied during the relevant period. Orange shaded boxes indicate where a price has increased or stayed the same between January 2021 and July 2021, while blue shaded boxes indicate a price decrease.

Since our July 2021 report, the prices paid by shippers for firm forward haul transportation on most pipelines have remained relatively stable. However, there were more significant changes on the AGP, RBP and TGP.

Table 6.1 shows that the minimum price paid for firm forward haul services on the AGP has fallen from $0.573/GJ to $0.421/GJ, a reduction of approximately 26%. The new minimum price is a result of the removal of an additional firm charge required to be paid by the shipper.
to APA under their existing GTA for capital works. The removal of the charge at this time was agreed in the GTA.

The maximum price paid for firm forward haul services on the RBP western haul increased by 11.7% from $0.628/GJ to $0.702/GJ. The new maximum price is a result of a shipper making use of a previously unused firm service under a multi-asset GTA.

The maximum price paid for firm forward haul services on the TGP has increased by 5.3% from $2.525/GJ to $2.660/GJ. The new maximum price is a result of the previous maximum price being escalated on 1 July 2021 by 1.5% above CPI for the previous 12 months. This price escalation mechanism is outlined in the shipper’s GTA.

In relation to standing prices, most of these prices remain unchanged. The only exceptions occurred on pipelines operated by APA, where most standing prices increased in line with inflation, except on the AGP where they fell by almost 38% from $0.547/GJ to $0.340/GJ due to a new approved access regime, in place from 2021 to 2026. The AGP is subject to full regulation, and the standing price reflects the reference tariff approved by the AER.

The RBP is also subject to full regulation. The AER approved 2021-22 reference tariff for long-term firm services on the RBP is $0.5802/GJ. The published tariff on APA’s website for this service is $0.7514/GJ, 29.5% higher than the reference tariff. This difference is significantly larger than the 13.8% difference we reported in July 2021, and the 8.3% difference as first reported in our January 2020 interim report.

The ACCC has previously asked APA about this difference, and APA informed the ACCC that the reference service is subject to the terms of the AER approved access arrangement, which includes provisions that differ from APA’s standard GTA that applies to its published tariffs. APA, for example, noted the access arrangement includes annual tariff adjustments to reflect changes in inflation and the cost of debt, and rebates from the sale of rebateable services, while the standard GTA only provides for tariffs to reflect changes in inflation.

Notably, none of the reasons that APA cited reflected differences in the actual service or quality of service. Rather, they relate to factors that have resulted in the reference tariff falling over the period, including as a result of the revenue that APA has earned from the provision of rebateable services, 70% of which is to be passed back through to shippers in the form of lower reference tariffs. APA’s decision not to pass this benefit through to its standard GTA published tariff is at odds with the tariffs available under full regulation.

APA’s decision to publish only the standard GTA tariff and not the reference service tariff is concerning as it has the potential to confuse prospective shippers on the pipeline. The upcoming changes to pipeline regulation (described in section 6.10) would require operators to publish standing terms for each service, which for scheme pipelines such as the RBP, must be based on the reference tariffs and non-price terms and conditions in the approved access arrangement for reference services. It is proposed to classify the rule as a civil penalty provision.

Based on the prices set out in table 6.1 and chart 6.1, shippers on the AGP are paying for firm forward haul services above the standing price despite this price reflecting the reference tariff determined by the AER. While most of these prices were agreed prior to the approval of the most recent reference tariffs by the AER, some were agreed after this time. This contrasts with shippers on the NGP, RBP western haul, SWQP eastern haul, PCA, EGP and MSP (from Moomba to Sydney), where the minimum and maximum firm forward haul prices are all below, or equal to, standing prices.

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Chart 6.1 shows the minimum, maximum and median prices paid by shippers for firm forward haul services between July 2016 and July 2021 on key pipelines in Queensland and the Northern Territory (Northern Pipelines) and the southern states (Southern Pipelines). The chart also shows standing prices, and from January 2020, prices payable for new contracts and variations entered in the relevant period.
Chart 6.1: Firm forward haul transportation prices (nominal)

Northern Pipelines

<table>
<thead>
<tr>
<th>$/GJ (Assumes 100% load factor)</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Median</th>
<th>Standing Price</th>
<th>Prices commencing in the relevant period (January 2020 on)</th>
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<tr>
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<td>$1.00</td>
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<tr>
<td>$0.50</td>
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<tr>
<td>$0.00</td>
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</tr>
</tbody>
</table>

- AGP (both directions) APA
- NGP* (to Mt Isa) Jemena
- CGP (to Mt Isa) APA
- QGP (to Gladstone) Jemena
- RBP Easternhaul (to Brisbane) APA
- RBP Westernhaul (to Wallumbilla) APA
- SWQP Westernhaul** (to Moomba) APA
- SWQP Easternhaul** (to Wallumbilla) APA

*Includes the cost of the mandatory nitrogen extraction service
** Includes compression costs.
Southern Pipelines

$/GJ (Assumes 100% load factor)

- Minimum
- Maximum
- Median
- Standing Price
- Prices commencing in the relevant period (January 2020 on)

$/GJ (Assumes 100% load factor)

MAPS
Southernhaul
Epic

PCA
(to Adelaide)
SEA Gas

EGP
(to Sydney)
Jemena

MSP
Culcairn to Sydney
APA

MSP
Moomba to Sydney
APA

TGP
(to Hobart and Zone 2)
Palisade

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites. *TGP pricing changed from a distance-based tariff to a zonal tariff as at 1 January 2018.
6.4.1. Transporting gas on multiple pipelines can involve significant costs, but multi-asset services can provide lower prices on some routes

As supply sources in the southern states become depleted in coming years, there is expected to be an increased reliance on transporting gas from north to south. The cost of doing so can be significant when moving gas through multiple pipelines, as is required when moving gas from production sources in the Northern Territory and Queensland to demand centres in southern states. Section 6.9 outlines shippers’ concerns with these costs which, in some cases, can be cost prohibitive.

Table 6.2 shows indicative firm forward haul costs for transporting gas to and from key locations in the east coast gas market. It is based on the sum of the minimum prices, standing prices and maximum prices paid by shippers for firm forward haul services in July 2021 for pipelines running between key locations. Prices shown for each individual pipeline between key locations may be for services supplied to different shippers. Orange shaded boxes indicate a price increase between January 2021 and July 2021, while blue shaded boxes indicate a price decrease. Unshaded boxes indicate where there was no change in price.

Costs to deliver gas to some locations may be reduced using APA’s multi-asset services when these are available. However, this does not assist demand centres serviced by non-APA pipelines. APA offers multi-asset firm services from the RBP to Sydney and Culcairn for $2.62/GJ/day, and from Wallumbilla or Mt Isa to Sydney or Culcairn for $2.02/GJ/day for commitments of 12 months or more.

When compared to the indicative costs in table 6.2, we can see that shippers seeking to transport gas to Sydney or Culcairn are generally able to secure discounts on the standing prices by using these multi-asset services rather than contracting on individual pipelines. However, this may not always be the case. For example, the sum of minimum prices from Kogan (near Brisbane) to Sydney (on the RBP Western haul, SWQP Western haul and MSP from Moomba to Sydney) in July 2021 was $2.36; and from Wallumbilla to Sydney (on the SWQP Western haul and MSP from Moomba to Sydney) in July 2021 was $1.73/GJ; which are both cheaper than APA’s multi-asset service offering for the same route.
Table 6.2: Indicative Firm Forward Haul Prices (as at July 2021)

<table>
<thead>
<tr>
<th>From:</th>
<th>Tennant Creek</th>
<th>Mt Isa (Brisbane)</th>
<th>Kogan Wallumbilla</th>
<th>Moomba</th>
<th>Adelaide</th>
<th>Sydney</th>
<th>Culcairn</th>
<th>Port Campbell</th>
<th>Longford</th>
</tr>
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<tbody>
<tr>
<td>To:</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mt Isa</td>
<td>Min $/GJ</td>
<td>2.06</td>
<td>2.87</td>
<td>2.25</td>
<td>1.71</td>
<td>2.53</td>
<td>2.87</td>
<td>2.87</td>
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<td></td>
<td>Max $/GJ</td>
<td>2.33</td>
<td>3.31</td>
<td>2.69</td>
<td>1.93</td>
<td>2.75</td>
<td>3.09</td>
<td>3.09</td>
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<td>Standing Prices $/GJ</td>
<td>2.33</td>
<td>3.25</td>
<td>2.63</td>
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<td>2.82</td>
<td>3.16</td>
<td>3.16</td>
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<td>Brisbane</td>
<td>Min $/GJ</td>
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<td>2.20</td>
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<td>Hobart</td>
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<td>Curtis Island LNG</td>
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<td>3.79</td>
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</tbody>
</table>

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites.

Notes: Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).

Standing prices have been used in cases where there are no minimum or maximum prices.

We have assumed that prices for transportation on the SWQP from Moomba to Ballera are 0.5 times the SWQP eastern haul tariff; and from Ballera to Moomba are 0.2 times the SWQP western haul tariff. This is based on information provided by APA. For example, prices from Mt Isa to Adelaide have been calculated as: CGP + 0.2 x SWQP western haul + MAPS southern haul.

* APA offers multi-asset firm services from the RBP to Sydney and Culcairn for $2.62/GJ/day for commitments of 12 months or more. ^ APA offers multi-asset firm services from Wallumbilla or Mt Isa to Sydney or Culcairn for $2.02/GJ/day for commitments of 12 months or more.
6.5. Prices for as available and interruptible transportation services have generally increased in line with inflation since January 2021

Table 6.3 outlines the median prices paid for firm forward haul services in July 2021, as well as the median, minimum and maximum prices paid for as available and interruptible transportation services in July 2021. The table also outlines the premium paid for as available and interruptible services over firm services by comparing the median price paid for each.

**Table 6.3: Firm, as available and interruptible service prices as at July 2021**

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Firm</th>
<th>As Available/Interruptible Service Price (as at July 2021)</th>
<th>Premium of as available and interruptible over firm prices (Med)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Med</td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>AGP</td>
<td>0.644</td>
<td>0.483</td>
<td>0.837</td>
</tr>
<tr>
<td>NGP</td>
<td>2.133</td>
<td>2.133</td>
<td>2.595</td>
</tr>
<tr>
<td>CGP</td>
<td>1.261</td>
<td>0.946</td>
<td>2.429</td>
</tr>
<tr>
<td>QGP (to Gladstone)</td>
<td>0.960</td>
<td>1.073</td>
<td>1.073</td>
</tr>
<tr>
<td>RBP Eastern haul</td>
<td>0.751</td>
<td>0.494</td>
<td>1.290</td>
</tr>
<tr>
<td>RBP Western haul</td>
<td>0.623</td>
<td>0.526</td>
<td>0.980</td>
</tr>
<tr>
<td>SWQP Western haul</td>
<td>1.217</td>
<td>1.089</td>
<td>1.945</td>
</tr>
<tr>
<td>SWQP Eastern haul</td>
<td>1.142</td>
<td>1.065</td>
<td>1.938</td>
</tr>
<tr>
<td>MAPS Southern haul</td>
<td>0.775</td>
<td>0.765</td>
<td>1.549</td>
</tr>
<tr>
<td>PCA</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EGP</td>
<td>1.290</td>
<td>1.443</td>
<td>1.731</td>
</tr>
<tr>
<td>MSP (Culcairn to Sydney)</td>
<td>0.426</td>
<td>0.325</td>
<td>1.031</td>
</tr>
<tr>
<td>MSP (Moomba to Sydney)</td>
<td>1.011</td>
<td>0.644</td>
<td>2.143</td>
</tr>
<tr>
<td>TGP</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data supplied by pipeline operators

In previous reports we have noted that pipeline operators prefer longer-term firm contracting and seek to incentivise this through pricing. This generally means that shorter-term non-firm services, like as available or interruptible services, are sold at a premium to firm services. In table 6.3 we can see that median prices paid by shippers in July 2021 for as available and interruptible services were between 3% and 62% greater than median prices paid for firm services. The most significant premiums appear to be on the SWQP, RBP and MSP from Moomba to Sydney. This may reflect a number of factors, including contractual congestion.

In the 2015 Inquiry we noted that there is no well-accepted regulatory principle for the pricing of as available or interruptible services in Australia, but the principle that has been adopted
in the EU and the US is that the price of as available or interruptible services should not exceed the price of firm capacity.\textsuperscript{168} We noted that the prices charged by some pipelines for as available, interruptible and backhaul services were excessive, and suggested that the pipelines in question face little constraint in the pricing of these services.

The premiums reported in table 6.3 indicate that transport costs have been, and will continue to be, even greater for shippers who are unable or unwilling to enter longer-term firm contracts with pipeline operators. This may create some risks given the expected increase in reliance on transport and compression services to move gas from Queensland to southern states over the coming years, combined with shippers appearing to seek shorter-term, more flexible transport services.

Chart 6.2 shows the minimum and maximum prices paid by shippers for as available and interruptible transportation services between July 2016 and July 2021, standing prices for these services and prices agreed in each relevant period (since January 2020) on Northern and Southern pipelines.

\textsuperscript{168} Article 14.1(b) of Regulation (EC) No. 715/2009 states that the price of interruptible capacity shall reflect the probability of interruption. This regulation has been interpreted by the Agency for Cooperation of Energy Regulators in Europe as requiring the price of interruptible capacity to be sold at a discount to the firm capacity price, with the level of the discount to reflect the risk (likelihood and duration) of interruptions, so that if the risk of interruption is low the discount should be low and vice versa. ACER, Framework Guidelines on rules regarding harmonised transmission tariff structures for gas, November 2013, p. 33. In the US, the price of interruptible services on interstate pipelines regulated by the Federal Energy Regulatory Commission (FERC) is capped at the firm rate, but any revenue derived from these services must be taken into account when calculating the firm rate so the pipeline doesn’t recover more than the allowed revenue.
Chart 6.2: As available and Interruptible transportation prices

Northern Pipelines

* Includes cost of mandatory nitrogen removal service
** Includes compression costs
^ This service is only available on contractually congested pipelines.

* Includes cost of mandatory nitrogen removal service
** Includes compression costs
^ This service is only available on contractually congested pipelines.
Southern Pipelines

- **Minimum**
- **Standing price**
- **Interruptible standing price**
- **Maximum**
- **Short-term firm standing price (APA only)**
- **Prices commencing in the relevant period (January 2020 on)**

^ APA interruptible service is only available on contractually congested pipelines.

Gas Inquiry 2017–2025
Since our January 2021 report the prices paid by shippers for as available and interruptible transport on most pipelines have increased with inflation (3.8% between June 2020 and June 2021).

The minimum prices paid for as available and interruptible services on the RBP eastern haul and western haul have decreased by 9.3% and 3.4% respectively. The new minimum prices are for varied contracts that have lower firm capacity rates, which have lowered the interruptible service prices in the same contracts. These contracts had either a significant term extension or an increase in as available MDQ, which may have led to the lower prices.

Similar to previous years, there is only one price reported for as available and interruptible services on the QGP northern haul. The previous maximum price paid for as available and interruptible services in July 2020 was under a two-year contract that has now ended.

We also note the large range in prices reported on some pipelines, particularly the MSP. This may be due to our pricing approach of including interruptible and short-term firm services on APA pipelines, which are priced at a fixed percentage below and above each shipper's firm rate respectively. We have also included bespoke as available prices.

6.6. Park and Loan prices continue to vary considerably across pipelines

Chart 6.3 shows the standing, maximum and minimum prices payable by shippers for park and loan services (both firm and as available or interruptible services) between July 2016 and July 2021, as well as the prices agreed in more recently negotiated contracts on northern and southern pipelines.

Park and loan services allow a shipper to store or take gas from a pipeline over a short-term period, with the gas then being returned (in the case of a loan service) or withdrawn (in the case of a park service) in the future. A shipper would not typically want to use these services on a long term basis as park services are much more expensive on a $/GJ/day basis than dedicated storage services, as can be seen in section 6.6 below. The benefit of using park and loan services is that they allow a shipper some flexibility in MDQ, but generally at a cheaper cost than overrun or other imbalance charges. Some pipelines will provide both park and loan services (generally at the same cost), while others provide only a park service.

As with haulage services, some pipeline operators offer park and loan services with different priorities. Shippers can reserve firm park MDQ or use as available park services. Pricing varies between pipelines as some pipeline operators charge a premium for firm park while others charge a premium for as available park services.
Chart 6.3: Park and loan prices

Northern Pipelines

$0.00 $0.10 $0.20 $0.30 $0.40 $0.50 $0.60 $0.70

$/GJ/day

- Minimum  - Maximum  - Standing price  - As available standing price  - Prices commencing in the relevant period (January 2020 on)

As available or interruptible

CGP APA

RBP APA

RBP APA

SWQP APA

QGP Jemena

Gas Inquiry 2017–2025
Southern Pipelines

$/GJ/day

- Minimum
- Maximum
- Standing price
- Interruptible standing price
- Prices commencing in the relevant period (January 2020 on)

* Does not include an administration fee also payable by shippers

* The firm price is based on Jemena’s premium park service, while as available and interruptible prices are based on the firm (square symbol standing prices) and as available (plus symbol standing price) park services.
Prices payable for park and loan services continue to vary considerably across pipelines. Similar to as available and firm haulage services, park and loan prices have generally increased in line with inflation. There are two exceptions:

- On the EGP, the minimum firm park prices have decreased by 5.1% as a shipper has signed a new contract with a lower park price.
- On the MSP the maximum firm park price has decreased. The shipper has multiple park prices and has allowed the highest cost park service to lapse.

6.7. Storage prices at the Dandenong LNG storage facility have increased significantly

The Dandenong LNG and Iona underground storage facilities (owned by APA and Lochard Energy, respectively) are the only facilities that currently provide storage services to third parties in the east coast gas market, however they provide different services.

The Dandenong LNG storage facility is used to store small volumes of gas to be injected quickly into the Victorian Transmission System (VTS). This gas is usually used to address short-term peaks and system security issues in Victoria. A large part of the cost of storing gas at Dandenong LNG is the liquefaction cost to turn the gas into LNG. In contrast, the Iona underground storage facility is a now-depleted conventional gas field that has been adapted to allow gas to be pumped back down into the reservoir and stored. The Iona facility is ordinarily used to store large volumes of gas during summer months, which is withdrawn in winter to meet seasonal demand for gas.

As the Iona and Dandenong storage facilities offer two different services, they do not compete directly with each other, nor do they face competition from other operators for similar services. This lack of competition affords each storage facility considerable market power when setting prices for their services.

These differences are reflected in each facility’s price structure. Reflecting the increased cost of turning gas into LNG and storing it, prices at Dandenong LNG are significantly higher on a per GJ basis than at Iona. Lochard charges injection and withdrawal charges as well as a fixed storage charge, but the injection and withdrawal charges make up a relatively small part of the overall cost of storage.

Table 6.4 shows the prices paid for storage at the two facilities.
### Table 6.4: Storage Prices

<table>
<thead>
<tr>
<th></th>
<th>July 2020 ($/GJ)</th>
<th>January 2021 ($/GJ)</th>
<th>July 2021 ($/GJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Iona gas storage</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed (per day)</td>
<td>0.015-0.025</td>
<td>0.015-0.026</td>
<td>0.015-0.026</td>
</tr>
<tr>
<td>Variable-SWP Injection</td>
<td>0.084-0.094</td>
<td>0.083-0.093</td>
<td>0.084-0.094</td>
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<tr>
<td></td>
<td>0.042-0.047</td>
<td>0.042-0.047</td>
<td>0.042-0.047</td>
</tr>
<tr>
<td>Variable-SEA Gas</td>
<td>0.014</td>
<td>0.014</td>
<td>0.014</td>
</tr>
<tr>
<td></td>
<td>0.084-0.094</td>
<td>0.083-0.093</td>
<td>0.084-0.094</td>
</tr>
<tr>
<td><strong>Dandenong gas storage</strong></td>
<td></td>
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</tr>
<tr>
<td>Storage (per day)</td>
<td>0.069-0.092</td>
<td>0.092</td>
<td>0.099-0.134</td>
</tr>
<tr>
<td>Liquefaction</td>
<td>1.301-1.704</td>
<td>1.301-1.704</td>
<td>1.694</td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data supplied by APA and Lochard Energy

*Note: Storage prices at Dandenong in July 2021 have been calculated by dividing the total amount paid by the user for firm vaporisation, by the total amount of storage provided to that user.*

Prices at the Iona gas storage facility have remained steady since January 2021. The amount of firm storage reservoir capacity contracted by users at Iona has increased from 19.8PJ across 9 users to 22.9PJ across 10 users from July 2020 to July 2021.

APA has restructured the contracting model for all new gas storage agreements at the Dandenong LNG storage facility signed since December 2020. Under the previous model, users contracted storage to achieve a certain amount of vaporisation (the service required to withdraw gas from storage). These vaporisation rights were allocated proportionally to the amount of gas each user held in storage. Under the new model, users contract a required amount of firm vaporisation, and are provided with an associated amount of storage capacity.

Storage prices at Dandenong in July 2021 have been calculated by dividing the total amount paid by the user for firm vaporisation, by the total amount of storage provided to that user.

APA claim that this new contracting model benefits users, as customers have more certainty around their ability to vaporise gas. As a result of the restructure, storage prices at the Dandenong storage facility have increased significantly since January 2021, and especially since July 2020. Storage now costs users between $0.099/GJ/day and $0.134/GJ/day. This represents a price increase for all users of between 8% and 46% since January 2021 and 44-46% since July 2020.

Over recent years, contracted storage capacity has decreased significantly at the Dandenong storage facility, from 517 TJ across 8 shippers in July 2019 to 188 TJ across 6 shippers in July 2021. Nearly all remaining users have contracted for a significantly decreased volume of storage.

Given the Dandenong facility is designed to provide gas on very high demand days, the decline in contracted capacity may have been a contributing factor to the high gas spot prices in Victoria in July 2021 (see section 4.3). As gas supply in the southern states decreases over the coming years storage facilities such as Dandenong LNG are expected to
be critical in maintaining supply. Increased prices and lowered contracted levels of storage are of concern and increase the risk of elevated spot prices and gas supply issues on high demand days.

As noted in our July 2021 interim report, new storage facilities in the south would be expected to increase competition and help put downward pressure on prices for storage services in the south. Lochard is working on increasing the withdrawal capacity of the Iona facility, while Golden Beach Energy is developing a similar storage facility in a gas reservoir off the coast of Victoria. See section 2.5.4 for more information on these developments.

Unlike pipeline operators, storage providers are not currently required to publish a standing price for storage services, however recently agreed reforms will address this (see section 6.11).

6.8. Pipeline capacity remains limited on a number of facilities that are used to transport gas south from Queensland

As noted in chapter 1, forecast demand slightly exceeds forecast supply in southern states for 2022. This highlights the importance of southern haul capacity for meeting the needs of users in the southern states. The following chart and figure highlight capacity issues on key pipelines throughout the east coast gas market.

Chart 6.4 shows our outlook for contracted capacity on major transmission pipelines between 1 November 2021 and 31 October 2024. It also includes our previous outlook for contracted capacity on these pipelines between 1 May 2021 and 31 April 2024, as reported in our July 2021 interim report.

Below this, figure 6.2 shows pipeline nameplate and contracted capacity to October 2022.
Chart 6.4 Proportion of pipeline capacity contracted between May 2021 and October 2024

Southern haul pipelines
Other pipelines

Sources: For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator’s website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed 11 October 2021). For other pipelines (i.e. the Roma to Brisbane Pipeline, the Amadeus Gas Pipeline, the Northern Gas Pipeline and the Carpentaria Gas Pipeline), the contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed 11 October 2021).
Figure 6.2: Pipeline capacity between 1 November 2021 and 31 October 2022
Our current pipeline capacity outlook in chart 6.4 shows the PCA, MAPS (northern haul), EGP, MSP, CGP, SWQP (eastern haul) and NGP have a reasonable amount of uncontracted capacity available.

However, there are other pipelines where capacity has been fully contracted, or close to fully contracted in the near term and over our whole period of analysis. This includes pipelines that are used to transport gas south from Queensland and the Northern Territory. This could pose a problem for shippers without firm capacity in 2022, if producers in the southern states experience any delays or difficulties producing gas from undeveloped 2P reserves or contingent resources (see chapter 1).

In comparison to our July 2021 interim report, there is less capacity available on the MSP from Moomba to Sydney, on the SWQP from Wallumbilla to Moomba, and on the CGP from Ballera to Mt Isa. Conversely there is more capacity available on the NGP from Tennant Creek to Mt Isa.

The southern haul capacity of the MAPS is fully contracted until January 2023. Despite the decrease in contracted capacity from January 2023 onwards, experience suggests that available capacity is likely to be similar to current levels as we approach 2023.

Uncontracted capacity is expected to change as contracts are executed and pipeline capacity is increased, for example through initiatives such as APA’s recent announcement to expand the capacity of the SWQP and MSP to transport gas to southern states by 25% (see section 2.5.2).

### 6.9. Physical flows on major pipelines often approach capacity

We have sourced information from pipeline operators on the actual gas transported on pipelines across the east coast between July 2020 and June 2021.

Figure 6.3 below shows the physical flows of gas on each pipeline in each direction between July 2020 and June 2021 in PJs. Where pipelines offer a backhaul service the flow is the net flow. On the RBP western haul flows appear to start around midway between Wallumbilla and Brisbane; this indicates that gas is not transported from Brisbane to Wallumbilla but instead from production fields in the Surat Basin. Flows along the TGP with receipt and delivery points within Victoria have been excluded.

The colour of each pipeline indicates the percentage of nameplate capacity that is utilised over the course of the year. Note that nameplate capacity figures include a number of key assumptions, including standard pipeline conditions (e.g. ambient temperature) and that 100% of the pipeline capacity is available for haulage services (i.e. not required for pipeline storage services).

The figure also shows the gross amount of gas injected and withdrawn from the Iona and Dandenong LNG storage facilities between July 2020 and June 2021. These show allocated, not physical flows. The up and down arrows show the quantities injected and withdrawn respectively.
Figure 6.3: Physical flows of gas between 1 July 2020 and 30 June 2021

Source: ACCC analysis of data supplied by pipeline operators
Figure 6.3 shows that many pipelines do not approach their theoretical physical capacity over the course of a year. However, the usage of pipelines is more complicated in practice. Some pipelines have a relatively flat demand profile over the course of the year, such as the CGP or QGP. Some pipelines, however, especially those that service retail markets which have a major winter heating load, show strong seasonality in their usage.

Table 6.5 sets out the physical volume of gas transported by month on east coast pipelines as a percentage of their nameplate capacity.
Table 6.5: Physical flows of gas as a percentage of nameplate capacity between 1 July 2020 and 30 June 2021

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Region</th>
<th>Jul-20</th>
<th>Aug-20</th>
<th>Sep-20</th>
<th>Oct-20</th>
<th>Nov-20</th>
<th>Dec-20</th>
<th>Jan-21</th>
<th>Feb-21</th>
<th>Mar-21</th>
<th>Apr-21</th>
<th>May-21</th>
<th>Jun-21</th>
</tr>
</thead>
<tbody>
<tr>
<td>TGP</td>
<td>South</td>
<td>21%</td>
<td>20%</td>
<td>16%</td>
<td>16%</td>
<td>13%</td>
<td>14%</td>
<td>13%</td>
<td>14%</td>
<td>15%</td>
<td>18%</td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>RBP</td>
<td>East</td>
<td>55%</td>
<td>45%</td>
<td>50%</td>
<td>50%</td>
<td>43%</td>
<td>49%</td>
<td>50%</td>
<td>52%</td>
<td>49%</td>
<td>41%</td>
<td>52%</td>
<td>61%</td>
</tr>
<tr>
<td></td>
<td>West</td>
<td>84%</td>
<td>77%</td>
<td>72%</td>
<td>42%</td>
<td>54%</td>
<td>33%</td>
<td>30%</td>
<td>33%</td>
<td>67%</td>
<td>68%</td>
<td>56%</td>
<td>79%</td>
</tr>
<tr>
<td>CGP</td>
<td>North</td>
<td>71%</td>
<td>74%</td>
<td>74%</td>
<td>62%</td>
<td>75%</td>
<td>76%</td>
<td>72%</td>
<td>72%</td>
<td>66%</td>
<td>70%</td>
<td>69%</td>
<td>69%</td>
</tr>
<tr>
<td></td>
<td>South</td>
<td>45%</td>
<td>45%</td>
<td>43%</td>
<td>26%</td>
<td>45%</td>
<td>41%</td>
<td>34%</td>
<td>35%</td>
<td>34%</td>
<td>38%</td>
<td>38%</td>
<td>40%</td>
</tr>
<tr>
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<td>East</td>
<td>14%</td>
<td>35%</td>
<td>45%</td>
<td>52%</td>
<td>72%</td>
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<td>50%</td>
<td>58%</td>
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<td>41%</td>
</tr>
<tr>
<td></td>
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<td>15%</td>
<td>11%</td>
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<td>41%</td>
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</tr>
<tr>
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<td>69%</td>
<td>51%</td>
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<td>26%</td>
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<td>26%</td>
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<td>0%</td>
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<td>11%</td>
<td>29%</td>
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<td>21%</td>
<td>18%</td>
<td>5%</td>
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<td>10%</td>
</tr>
<tr>
<td>MAPS</td>
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<td>85%</td>
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<td>49%</td>
<td>37%</td>
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<tr>
<td>PCA</td>
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<td>25%</td>
<td>27%</td>
<td>33%</td>
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<td>28%</td>
<td>24%</td>
<td>29%</td>
<td>34%</td>
</tr>
<tr>
<td>NGP</td>
<td>East</td>
<td>58%</td>
<td>59%</td>
<td>59%</td>
<td>36%</td>
<td>57%</td>
<td>51%</td>
<td>50%</td>
<td>50%</td>
<td>51%</td>
<td>55%</td>
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<td>QGP</td>
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<td>89%</td>
<td>87%</td>
<td>87%</td>
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<td>91%</td>
<td>94%</td>
<td>96%</td>
<td>94%</td>
</tr>
<tr>
<td></td>
<td>South</td>
<td>10%</td>
<td>5%</td>
<td>0%</td>
<td>0%</td>
<td>2%</td>
<td>0%</td>
<td>2%</td>
<td>7%</td>
<td>7%</td>
<td>7%</td>
<td>13%</td>
<td>13%</td>
</tr>
<tr>
<td>EGP</td>
<td>North</td>
<td>63%</td>
<td>68%</td>
<td>69%</td>
<td>69%</td>
<td>60%</td>
<td>62%</td>
<td>68%</td>
<td>59%</td>
<td>61%</td>
<td>73%</td>
<td>71%</td>
<td>83%</td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data supplied by pipeline operators
Even though the SWQP, MSP, and MAPS do not approach their theoretical maximum quantity of gas transported over the course of the year, over the winter months these pipelines come much closer to approaching their capacity. These limits highlight the importance of not only the SWQP and MSP capacity upgrades outlined in section 2.5.2, which will allow more gas to flow during peak months, but also the storage investment at the Iona storage facility and the proposed Golden Beach project, which will allow more gas to flow south during lower-demand months and then stored.

These monthly limits are further complicated by demand for gas powered generation. Gas fired power plants may run on only a small number of days per year but require significant hourly flexibility during those days when renewable energy production is low. This means those pipelines which do not approach theoretical maximum usage may still face limits on high demand days.

6.9.1. Shippers seeking to transport gas south during winter months using non-firm services face the risk of interruption

Some shippers that do not have firm capacity on southern haul facilities may experience difficulties transporting gas south using as available/interruptible services or the Day Ahead Auction for contracted but unnominated capacity (DAA). We have examined the use of these facilities over the last 18 months to better understand how likely this is.

The results of this analysis are set out in chart 6.5, with the monthly utilisation measure representing the minimum and maximum physical gas flows in each month for the period 1 June 2020 to 15 October 2021, expressed as a percentage of the facility’s nameplate capacity.

Chart 6.5: Range of daily percentage of nameplate capacity used each month

As this chart shows, the MSP, SWQP and Wallumbilla compression facilities did not experience any physical constraints over the last 18 months. However, there were winter days where utilisation of the SWQP exceeded 90 per cent. Utilisation of the MAPS exceeded 100 per cent in a number of months during, and leading up to, winter in 2020 and 2021.

Since July 2020 report we have reported that shippers seeking to rely on non-firm services, including as available/interruptible services and the DAA to transport gas to southern states during winter months are likely to experience an increasing risk of not being able to secure transportation. This remains the case, particularly on the SWQP and MAPS. In a positive development, APA has commenced upgrades to the western haul capacity of the SWQP.
and the southern haul capacity of the MSP, which will allow more gas to be supplied from the north into southern states. This is discussed further in chapter 2.

As reported previously, in those instances where utilisation has exceeded 100% on the MAPS, Epic has been able to increase volumes above nameplate capacity in the short term to meet peak demand. However, this is not a long-term solution if, as forecast, there will be an increasing need to transport gas from Queensland to southern states.

In August 2021 the AER noted that use of the DAA increased by 9.3 PJ over 2020–21, with more active participants in the market and more auction facilities traded on.169 They noted that GPG Gentailers, Exporters and Producers have been increasing their utilisation of the DAA, with the majority of this being won on the MSP and SWQP, including Wallumbilla Compression Facility B. The AER noted that the DAA continues to provide flexibility for participants to deliver gas in response to fluctuating demand and prices, especially between northern and southern markets.

6.9.2. Firm services are the key service on all pipelines, but increasingly significant volumes are transported under non-firm services on some pipelines

Chart 6.6 shows the quantity of gas transported on each pipeline, broken down by the type of service used to transport it. Overrun services have been included with the relevant service where applicable.

Chart 6.6: Service use across different pipelines

The chart shows that gas is overwhelmingly still transported under firm services on all pipelines across the east coast. The Day Ahead Auction has grown significantly in use; more gas is transported under the DAA than using as available and interruptible services on the western haul portions of the SWQP and RBP and makes up 25% of the gas transported

north on the MSP. However, on most pipelines as available and interruptible services remain the largest non-firm service.

There does not seem to be a correlation between contractual congestion and type of service used. Both the MAPS and SWQP are contractually congested, but on the MAPS nearly all gas is transported by firm service, while the SWQP sees significant uptake of interruptible and DAA services.

Service use can also vary across the year. Chart 6.7 shows that physical flows on the SWQP eastern haul using firm services are consistent across most of the year (aside from during mid-winter), but extra gas is transported using interruptible services over the summer months. This is in contrast to western haul delivery points, which experience little use in summer months, but firm, interruptible and Day Ahead Auction services are used in winter months.

**Chart 6.7: Physical flows of gas by service on the SWQP**

![Gas transported (PJ) by service on the SWQP eastern haul from July 2020 to June 2021](chart)

- **Firm**
- **Interruptible**
- **Day Ahead Auction**
6.10. Shippers' recent experiences with transport and storage services and service providers

In August and September 2021, the ACCC approached a range of shippers to better understand their recent experiences with transport and storage services and service providers. The ACCC met with eight shippers, including LNG exporters, producers, retailers and gas market traders. Collectively, these shippers hold transport positions on most pipelines in the east coast gas market.

**Transport prices remain high and can act as a barrier for shippers wanting to enter new markets**

Many shippers identified high transport prices as one of their key concerns and suggested that transport costs can act as a barrier when trying to enter new markets further away from supply sources.

Shippers noted that they have attempted to enter new markets but found that their prices are uncompetitive compared to local suppliers due to transport costs. One shipper noted that more than half of the total cost of moving gas from their existing market into a new one would be for firm transport, which would increase if it was shipped using an as available service. Another shipper noted that 'it will be difficult for Queensland to do the heavy lifting in the future to fix gas supply issues if transport is constrained.'

One shipper suggested that minimising transport costs would significantly reduce the price of gas in the east coast gas market. Several shippers noted their frustrations that the cost to transport gas can often be more than the cost to produce gas, with one shipper suggesting that buyers won't be able to afford gas for much longer if production and transport prices continue to rise. A number of shippers couldn't understand how transport costs were so high and continued to rise, particularly on some of the older pipelines. These shippers suggested pipeline operators’ initial costs should have been recovered by now given the cost of the infrastructure and their rates of return.
Shippers are increasingly seeking different services to those generally offered by pipeline operators

Many of the shippers we spoke to noted that the services generally offered by pipeline operators are less flexible than the services they want, or the services that their customers want. These shippers noted that there can be a disconnect between the services offered by pipeline operators and the services sought by customers, with pipeline operators often preferring longer term contracts with less flexibility, while customers are increasingly seeking shorter-term contracts with more flexibility.

One shipper noted that, while historically shippers took much longer-term positions, the world has moved on and buyers are looking for shorter-term positions, including for gas supply. This shipper suggested that while shippers might be seeking shorter-term positions, they have much larger portfolios which should be compensating pipeline operators to some degree.

Several shippers noted that the inflexibility of pipeline operators mean it is either becoming cost prohibitive for them to contract with buyers who want more flexibility or has made them rethink their transportation requirements. One shipper noted that a number of their transport contracts are due to expire in CY2021 and CY2022. This shipper noted that they are considering whether to recontract long-term transport positions in the future. This shipper noted that they would be moving to separate out commodity and transport services for their customers going forward.

Several shippers noted they have previously tried to arrange 'bundled' services to transport gas across multiple pipelines with different operators and into new markets. These shippers noted this has been difficult and suggested that pipeline operators have either been unwilling to offer these services or negotiate between themselves. Relatedly, one shipper noted that they have previously had difficulty combining individual services across multiple pipelines and said that APA's introduction of multi asset transport services has been helpful in this regard.

Shippers generally find it difficult to negotiate with pipeline operators

Shippers seemed to have mixed experiences when negotiating with pipeline operators. In general, they noted that while they might have good working relationships at an individual level, they often lack bargaining power in negotiations.

One shipper noted that they lack the ability to create 'competitive tension' in negotiations because they're negotiating with monopoly service providers. This shipper noted that they lack the specific expertise in pipeline operation to interrogate information, such as some of the financial information published by pipeline operators under Part 23, that could assist them in a negotiation.

A number of shippers said it is often difficult for them to negotiate discounts on standing prices, or terms or conditions that differ from standard contracts. One shipper noted this is particularly the case for regulated pipelines where few changes to standard terms and conditions can be made. One shipper reported that if they're trying to secure different terms and conditions (including increased flexibility) through a negotiation, they often have to take on more risk (i.e. a longer-term contract or a smaller portfolio) as a trade-off. This shipper found that they have very little leverage in negotiations other than the size and scale of the position they're taking.

One shipper noted that the potential to use formal dispute resolution mechanisms has been referred to during negotiations in the past, and while they have not proceeded with formal dispute resolution, they have been able to use this as leverage to negotiate with pipeline
operators. This shipper noted that while this was somewhat helpful, the formal process they went through was not as flexible as a standard informal negotiation.

One shipper said that they believe the possible introduction of LNG import terminals has threatened pipeline operators' positions as monopoly providers of transport services (as import terminals would provide an alternate way for gas to enter the market) and has generated the first bit of competitive tension they have seen.

**While the Day Ahead Auction has been a positive market development, some shippers thought more could be done to free up spare pipeline capacity**

Many of the shippers we spoke to advised that the introduction of the Day Ahead Auction (DAA) for contracted but unnominated capacity has been good for the market.

Despite this, several shippers said that the DAA is not suitable for everyone. One shipper noted that they do not currently participate in the DAA partly because of the minimum volumes required and large setup costs. Another shipper noted that they have not used the DAA because they have firm requirements and have often already organised transport beforehand. A number of shippers reported that if they need to trade, they often use swaps as a way to manage supply and demand risks, which negates the need for transport altogether.

A number of shippers suggested that more could be done to free up available pipeline capacity. One shipper noted that they are unable to secure firm capacity on a major pipeline where the DAA is not available and suggested that the DAA should be made available on more pipelines. Others have noted that the success of the DAA may result in the DAA being less available in the future, as it provides an incentive for shippers to reduce their firm capacity to prevent competitors from accessing their capacity at reduced cost, reducing the availability of spare contracted capacity. Another shipper suggested that any uncontracted or unutilised capacity should also be made available.

**There has been an improvement in the amount of publicly available information on transport services.**

The shippers we spoke to noted there is much more information on the east coast gas market available to them now than there has been previously, and that this provided them with a useful snapshot of the market.

However, several shippers noted that some of this information, particularly the financial information published by pipeline operators under Part 23, is complicated and difficult to use to help inform negotiations. Many shippers noted that they either have not, or rarely, used this information. One shipper said that they appreciate the move to more transparency in the market but that the information is complex and tends to support published tariffs. This shipper noted that they (the shipper) lacked the expertise to interrogate and analyse the information, which could help inform them in a negotiation.

One shipper noted that the available information has been informative but has not led to them getting anything less than the standing offer. For this shipper, this information simply indicates the relative disadvantage they're at relative to other shippers who have been able to secure discounts.

**6.11. Upcoming changes to pipeline regulation are expected to help users in their negotiations with pipeline operators and provide greater price transparency.**
In May 2021, Energy Ministers released a Decision Regulation Impact Statement (Decision RIS) identifying an agreed package of reforms to improve gas pipeline regulation. The reforms will change gas pipeline regulation to:

- implement more effective constraints on exercises of market power by pipeline operators
- facilitate access to pipelines that would not otherwise provide such access
- provide greater support for commercial negotiations between shippers and pipeline operators
- streamline the governance arrangements for pipeline regulation.

In September 2021, Energy Ministers released a draft legislative amendment package for consultation, detailing the changes required to the National Gas Law and National Gas Rules (NGR) to implement the agreed reforms.

The package includes reforms agreed to as part of a separate Decision Regulation Impact Statement on measures to improve transparency in the gas market. These measures include changes that require storage and stand-alone compression facility operators to publish standing terms, standing prices and actual prices paid by users, on their website.

Subject to completion of the regulatory amendment process, it is anticipated that the new framework will commence in 2022.

6.11.1. Effective enforcement and compliance will be critical to the success of these reforms

The AER has an existing role in monitoring and reporting on gas pipeline regulation and ensuring compliance, including monitoring on the information disclosure requirements of Part 23 of the NGR.

In our July 2019 report we noted concerns with the operation of Part 23 of the NGR. Pipeline operators did not appear to be taking the information disclosure obligations seriously, given the significant gaps and calculation errors.

Effective monitoring and enforcement of the reforms by the AER will be critical in ensuring they have the intended effect. In June 2021, the AER announced one of its key enforcement and compliance priorities for 2021-22 was to ‘(e)nsure service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations’.  

The ACCC welcomes this announcement from the AER as an important step in improving outcomes for users of these services and improving compliance in advance of the upcoming reforms.

6.11.2. The ACCC is concerned about South Australia’s intention to derogate from the requirement for pipelines to publish individual prices.

In our July 2020 and January 2021 interim reports, we found that the prices payable by some shippers on the two pipelines servicing South Australia (MAPS and PCA) had increased sharply between July 2019 and January 2020. We noted that the extent of these longer-term increases continued to raise concerns about the lack of competitive constraint on the prices charged by these two pipelines.

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In September 2021, the South Australian Department for Energy and Mining released a consultation paper seeking stakeholder feedback on their intended derogation from individual price reporting requirements, under the agreed package of reforms to improve gas pipeline regulation.

The consultation paper noted that ‘Stakeholders suggested the requirement on service providers to publish individual prices paid by shippers will reduce the flexibility and ability of service providers to offer bespoke services that provide the ability of South Australian businesses to successfully negotiate necessary gas contracts to undertake their business operations in South Australia.’

The ACCC provided a submission to the South Australian Government noting our concerns with the proposed derogation on transparency and consistency grounds, and rejecting the suggestion that individual price reporting would inhibit flexibility or the ability of service providers to offer ‘bespoke’ services. Further, we indicated that the proposed derogation is counter to the interests of South Australian users as they will be at a relative disadvantage to interstate users in their negotiations with service providers. The ACCC will continue to monitor these developments and provide feedback as appropriate, particularly given our previous observations about longer-term price increases on pipelines servicing South Australia.

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172 [Insert link to ACCC Submission]
A. Reserves and resources

To inform the longer term supply outlook, the ACCC sought the following information from producers:173

- the holdings of reserves and resources in the east coast (onshore and offshore) and the Northern Territory (onshore only) as at 30 June 2021 and the gas price assumptions used to assess the commerciality of reserves
- the movement in 2P reserves that occurred between 30 June 2020 and 30 June 2021 and an explanation for any material upgrade or downgrade in this period, and
- the development status of their gas fields and the main barriers to the commercial recovery of contingent resources.

The remainder of this appendix provides an overview of the reserves and resources reporting framework used by the ACCC and provides more detail on the reserves and resources estimates reported by producers as at 30 June 2021.

A.1 Reporting framework used for reserves and resources

When a gas reservoir is discovered, the gas within the reservoir can be classified as either a reserve or resource, depending on its commerciality. Reserves are those quantities that are expected to be commercially recoverable. Contingent resources on the other hand, are those quantities that are potentially recoverable but not yet commercial to develop, due to one or more contingencies (e.g. there is currently no viable market, the commercial recovery depends on technology under development, or the evaluation of the accumulation is insufficient to assess commerciality).174

Within each category of reserves and resources there are different confidence levels associated with the ability to recover the relevant quantities (for instance, reserves may be classified as proved, probable, or possible, while contingent resources may be classified as low, best or high estimate). However, 2P (proved plus probable) reserves and 2C resources are often viewed as the best estimates of reserves and resources, because they represent the “most realistic assessment of a project’s recoverable quantities” (see Table A.1).175

To understand the range of potential recovery outcomes, producers were asked to provide the best estimate of their 1P, 2P and 3P reserves (broken down into developed and undeveloped reserves) and 2C resources in the east coast (onshore and offshore) and the Northern Territory (onshore only) as at 30 June 2021. Producers were also asked to provide a range of information on the gas fields in which the reserves and resources are located, the main barriers to the commercial recovery of 2C resources in a field, and the supplier’s intentions for the future development of the field. This information was collected using relevant concepts in the Society of Petroleum Engineers’ Petroleum Resources Management System (PRMS).176

In addition to this information, producers were asked to report on the movement in 2P reserves between 30 June 2020 and 30 June 2021 and the gas price assumptions underpinning their reserves and resources estimates.

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173 The term ‘producers’ is used in this appendix to describe holders of gas reserves and resources, including entities currently producing gas and those that are not currently producing but have an interest in gas reserves and/or resources.
174 Society of Petroleum Engineers, Petroleum Resources Management System (PRMS), revised June 2018, p. 3.
175 ibid, p. 14.
Note that PRMS is a widely used principles-based standard that provides for a consistent approach to the calculation of petroleum quantities.
The reserves and resources estimates reported by producers represent their net revenue interests (i.e. a producer’s revenue share of gas sales after deducting royalties and share of production owing to others under applicable lease and fiscal terms)\(^{177}\) in the sales quantities of gas (i.e. quantities available for sale excluding quantities consumed in operations, flared or lost in operations) from all gas containing fields.

Further detail on the information the ACCC sought from producers is set out in Table A.1.

**Table A.1: Information collected from producers and bases on which it was collected**

<table>
<thead>
<tr>
<th>Type</th>
<th>Information requested</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reserves</strong></td>
<td></td>
</tr>
<tr>
<td>1P (proved)</td>
<td>Have at least a 90% probability that quantities recovered will equal or exceed the estimate</td>
</tr>
<tr>
<td>2P (proved + probable)</td>
<td>Have at least a 50% probability that quantities recovered will equal or exceed the estimate</td>
</tr>
<tr>
<td>3P (proved, probable, possible)</td>
<td>Have at least a 10% probability that the quantities recovered will equal or exceed the estimate</td>
</tr>
<tr>
<td>Broken down into developed(^{178}) and undeveloped(^{179}) reserves</td>
<td></td>
</tr>
<tr>
<td><strong>Resources</strong></td>
<td></td>
</tr>
<tr>
<td>2C (best estimate of contingent resources)</td>
<td></td>
</tr>
<tr>
<td><strong>Gas field information</strong></td>
<td>Information on whether the field is:</td>
</tr>
<tr>
<td></td>
<td>• currently producing, approved for development, or at another stage of development</td>
</tr>
<tr>
<td></td>
<td>• a conventional gas field, coal seam gas field, or another type of unconventional gas field</td>
</tr>
<tr>
<td></td>
<td>• a dry gas field (mostly methane), gas condensate field (mainly condensates or liquid hydrocarbons) or an oil field (where gas is found associated with oil).</td>
</tr>
<tr>
<td><strong>Development status</strong></td>
<td>Information on:</td>
</tr>
<tr>
<td></td>
<td>• the main barriers to the commercial recovery of 2C resources in a field</td>
</tr>
<tr>
<td></td>
<td>• the suppliers’ intentions for the future development of a field that has:</td>
</tr>
<tr>
<td></td>
<td>• been approved for development, including the best estimate of when supply would commence, the average annual quantity of gas to be produced, the main activities required to commence production and the key risks</td>
</tr>
<tr>
<td></td>
<td>• not yet been approved for development, including the best estimate of when a final investment decision will be made, when supply could commence, the average annual quantity of gas to be produced, the main activities required to commence production and the key risks.</td>
</tr>
<tr>
<td><strong>Movements in 2P Reserves</strong></td>
<td>Movements in reserves over the last 12 months broken down into:</td>
</tr>
<tr>
<td></td>
<td>• production</td>
</tr>
<tr>
<td></td>
<td>• extensions of a field’s proved area (i.e. changes resulting from the enlargement of the gas field’s proved area)</td>
</tr>
<tr>
<td></td>
<td>• net acquisitions (i.e. net changes resulting from the acquisition or disposal of an interest in an existing gas field)</td>
</tr>
<tr>
<td></td>
<td>• reserves upgrades (i.e. changes resulting from the commercialisation of resources or reclassification of 3P to 2P reserves)</td>
</tr>
<tr>
<td></td>
<td>• reserves downgrades (i.e. changes resulting from the reclassification of 2P reserves to 3P reserves or contingent resources)</td>
</tr>
<tr>
<td></td>
<td>• other revisions.</td>
</tr>
<tr>
<td><strong>Gas price assumptions</strong></td>
<td>Information on the gas price assumptions used to assess a project’s commerciality, with separate assumptions reported for both contracted and uncontracted reserves.</td>
</tr>
<tr>
<td><strong>Other information</strong></td>
<td>Date on which reserves and resources were estimated, the method used to develop the reserves and resources estimates and whether the estimates were developed internally or externally by a qualified gas industry professional.</td>
</tr>
</tbody>
</table>

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\(^{177}\) Royalty refers to a type of entitlement in a resources project. It is commonly retained by a resource owner (lessor) when granting rights to a producer (lessee) to develop and produce the resources.

\(^{178}\) Quantities expected to be recovered from existing wells and facilities.

\(^{179}\) Quantities expected to be recovered dependent on investments being made to bring associated wells and facilities online.
### A.2 Reserves and resources estimates as at 30 June 2021

Table A.2 sets out producers' best estimates of their 1P, 2P and 3P reserves and 2C resources in the east coast (onshore and offshore) and the Northern Territory (onshore only) as at 30 June 2021, while box A.1 provides an overview of the gas price assumptions used by producers to assess the commerciality of reserves.

<table>
<thead>
<tr>
<th></th>
<th>Reserves</th>
<th>Contingent Resources</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>1P</td>
<td>2P</td>
</tr>
<tr>
<td><strong>East coast gas market</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bowen Basin</td>
<td>4,034</td>
<td>6,049</td>
</tr>
<tr>
<td>Surat Basin</td>
<td>10,820</td>
<td>23,131</td>
</tr>
<tr>
<td>Galilee Basin</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Clarence-Moreton Basin</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cooper Basin</td>
<td>410</td>
<td>1,003</td>
</tr>
<tr>
<td>Gippsland Basin</td>
<td>1,319</td>
<td>1,968</td>
</tr>
<tr>
<td>Otway Basin</td>
<td>360</td>
<td>655</td>
</tr>
<tr>
<td>Bass Basin</td>
<td>95</td>
<td>145</td>
</tr>
<tr>
<td>Sydney Basin</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Gunnedah Basin</td>
<td>9</td>
<td>15</td>
</tr>
<tr>
<td><strong>Total east coast (onshore and– offshore)</strong></td>
<td><strong>17,047</strong></td>
<td><strong>32,968</strong></td>
</tr>
<tr>
<td><strong>Onshore Northern Territory</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amadeus Basin</td>
<td>188</td>
<td>245</td>
</tr>
<tr>
<td>McArthur Basin (Beetaloo sub-basin)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total NT (onshore)</strong></td>
<td><strong>188</strong></td>
<td><strong>245</strong></td>
</tr>
<tr>
<td><strong>Total East Coast + NT</strong></td>
<td><strong>17,235</strong></td>
<td><strong>33,213</strong></td>
</tr>
<tr>
<td>CSG</td>
<td>81%</td>
<td>80%</td>
</tr>
<tr>
<td>Conventional natural gas</td>
<td>13%</td>
<td>11%</td>
</tr>
<tr>
<td>CSG plus conventional natural gas in field</td>
<td>5%</td>
<td>7%</td>
</tr>
<tr>
<td>Other unconventional gas</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Conventional plus other unconventional in field</td>
<td>1%</td>
<td>1%</td>
</tr>
</tbody>
</table>

Source: ACCC analysis of data supplied by gas producers.

Notes:
1. Totals may not add up due to rounding.
2. The estimates in this table exclude the Leigh Creek Energy Project in South Australia because this project is intended to produce ‘synthetic natural gas’, and the ACCC understands that the technology required to do so is still being tested by Leigh Creek Energy (including a number of environmental studies) and that further environmental approvals are required before commercial quantities of gas can be produced.
3. The estimates provided by a small number of producers include relatively small volumes of ethane and carbon dioxide.
4. The Cooper Basin estimates include estimates for the Eromanga and Warburton basins.
5. The ‘CSG plus conventional natural gas in field’ and the ‘Conventional plus unconventional in field’ categories refer to the two types of gas that have come from the same field.
Figure A.1: Key gas basins in the east coast and Northern Territory
Box A.1: Gas price assumptions underpinning reserves and resources

Gas prices are a key determinant of a project’s commerciality. As part of the ACCC’s request for information, producers were asked to provide the gas price assumptions used to assess the commercial viability of contracted and uncontracted gas over the period 2021–2025. These assumptions are summarised in chart A.1, with separate markers used to identify the assumptions used for contracted and uncontracted reserves.

Chart A.1: Price assumptions underpinning reserve estimates (real $2021)

Source: ACCC analysis of data obtained from producers.

Chart A.1 shows that the gas price assumptions vary markedly across producers, with the gas price assumptions underpinning the current estimates of:

- Contracted reserves between 2021 and 2025 ranging from $4.37/GJ–$10/GJ and averaging $7.32/GJ, which is lower than the $7.73/GJ average observed in 2020.¹⁸⁰

- Uncontracted reserves between 2021 and 2025 ranging from $4.10/GJ–$11.73/GJ and averaging $7.46/GJ, which is lower than the $7.56/GJ average observed in 2020.¹⁸¹

In relation to uncontracted reserves, it is worth noting that some producers have previously stated that their price assumptions for uncontracted reserves do not necessarily reflect their expectations about the price they expect to receive in the short to medium term (i.e. because they are used to assess the viability of reserves over the longer term) and may change each time reserves are estimated.

It is also worth noting that the adoption of lower gas price assumptions for uncontracted reserves can result in reserves that were previously considered commercial to recover no longer being commercial to recover, which can then trigger a reclassification of reserves to contingent resources. Conversely, the adoption of a higher gas price assumption can result in reserves that were previously considered uncommercial becoming commercial, which can then trigger a reclassification of contingent resources to reserves.

¹⁸¹ ibid.
Table A.2 shows the quantity of 2P reserves in the east coast and onshore Northern Territory. Overall, there are currently 33,213 PJ, 52% of which are classified as proved reserves and the remainder as probable reserves.

The majority of these 2P reserves are located in CSG fields in Queensland, with 70% of 2P reserves located in the Surat Basin and 18% in the Bowen Basin (see chart A.2).

The remaining 2P reserves are located in offshore Victoria (8%), the Cooper Basin (3%), the Amadeus Basin (0.7%), the Gunnedah Basin (0.05%) and the Sydney Basin (0.007%).

**Chart A.2: 2P reserves by basin (as at 30 June 2021)**

The chart above does not illustrate either the downside risk or the potential upside associated with these 2P reserve estimates. These can be observed in the 1P and 3P reserves estimates:

- **1P reserves (17,235 PJ)** being over 48% lower than the 2P reserves estimate
- **3P reserves (40,659 PJ)** being just 22% higher than the 2P reserves estimate.

These estimates suggest there is material downside risk to the 2P reserves estimates. This is particularly the case in the Surat and Cooper basins, where 1P reserves account for around 47% and 41% of 2P reserves, respectively. Also, there appears to be limited upside potential at present. This is shown by the relatively small increases in 3P estimates, which take into account possible reserves.

As discussed in further detail in section A.4, the 2P reserve estimates as at 30 June 2021 are 1,393 PJ lower than what they were as at 30 June 2020. 1P and 3P reserves are also lower, with 1P reserves 713 PJ lower and 3P reserves 1,510 PJ lower. 2C resources, on the other hand, are 335 PJ higher.
Like 2P reserves, the majority of 2C resources are located in Queensland. As at 30 June 2021, there were 38,986 PJ of 2C resources, 34% of which were located in the Bowen Basin, 21% in the Surat Basin and 7% in the Galilee Basin (see chart A.3).

The McArthur Basin in the Northern Territory, which includes the Beetaloo sub-basin, also contains a significant quantity of 2C resources (18%), as does the Gunnedah Basin in New South Wales (7%). While CSG accounts for the majority of the 2C resources (64%), other unconventional sources of gas (19%) (e.g. tight gas and shale gas) located primarily in the Bowen, McArthur and Cooper basins, are starting to account for an increasing proportion of 2C resources over the last three years.

As noted in prior reports, producers can face a range of technical challenges when developing CSG and other unconventional gas fields. A significant degree of uncertainty therefore surrounds whether these contingent resources will be commercially recoverable in the future.

Chart A.3: 2C resources by basin (as at 30 June 2021)

A.3 Concentration of reserves and resources

Chart A.4 shows the proportion of 2P reserves and 2C resources held by producers in the east coast and onshore Northern Territory as at 30 June 2021.
The chart shows over 80% of 2P reserves are currently held by LNG producers in Queensland, either through ownership or through gas purchases from other related entities. APLNG holds the greatest share (34%), QGC holds the second highest share (14%) and has also acquired the bulk of Arrow Energy’s 2P reserves (17%), while Santos-GLNG controls the third highest share (18%).

Amongst the other producers, Esso, BHP, Beach Energy and Senex each hold around 2% of 2P reserves, Westside holds 1.5% and the remaining reserves are held by a range of small to mid-tier producers (i.e. AGL, Armour Energy, Blue Energy, Central Petroleum, Cooper Energy, Denison Gas, Macquarie Mereenie, Mitsui, OG Energy, CleanCo, Comet Ridge and Tri-Star).

The story differs somewhat at a contingent resource level, with LNG producers currently holding around 54% of 2C resources. Other relatively large holders of 2C resources include

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Origin and Falcon Oil through their joint venture interests in the McArthur Basin (Beetaloo sub-basin) (18%), Galilee Energy through its interests in the Galilee Basin (8%), Westside (4%) and Blue Energy (3%) through their respective interests in the Bowen Basin. The remainder are held by a range of small to mid-tier explorers and producers.

A.4 2P reserves have continued to fall between 2020 and 2021

Chart A.5 sets out the changes in 2P reserves that occurred between 30 June 2020 and 30 June 2021.

Chart A.5: Changes in 2P reserves in the east coast and onshore Northern Territory, 30 June 2020 to 30 June 2021

This chart shows 2P reserves continued to decline in the east coast and onshore Northern Territory in the 12 months to 30 June 2021. 2P reserves are expected to fall by 4% (1,393 PJ) to 33,213 PJ. The decline over this period can largely be attributed to production (1,978 PJ) and reserves downgrades183 (1,117 PJ), which were not sufficiently offset by the additions from reserves upgrades184 (1,548 PJ), net acquisitions (92 PJ) and other upward revisions (58 PJ).

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183 The term ‘reserves downgrade’ is used in this context to refer to changes in 2P reserves resulting from the reclassification of 2P reserves to 3P reserves or contingent resources.

184 The term ‘reserves upgrade’ is used in this context to refer to changes in 2P reserves resulting from the commercialisation of resources or the reclassification of 3P to 2P reserves.
This year is the fourth year we have reported on a decline in 2P reserves. 2P reserves have fallen by around 23% (10,192 PJ) in gross terms since 30 June 2017. The magnitude of this decline is a continuing concern of the ACCC, particularly given that over 90% of the decline has occurred in Queensland, which the east coast market, in particular the southern states, has become increasingly reliant upon. Of particular concern is the reserves downgrade and other downward revisions that have occurred in the Bowen and Surat basins, with over 8,157 PJ of 2P reserves in the Bowen and Surat basins written down since 2017. While there have been some offsetting reserves upgrades in these basins over the same period, on a net basis 2P reserves in these two basins have been downgraded by over 4,595 PJ.

Further detail on the changes in 2P reserves that have occurred in each basin in the east coast and onshore Northern Territory over the last 12 months can be found below.

**Changes in 2P reserves by basin**

Table A.3 sets out the changes in 2P reserves that have occurred in each basin over the last 12 months and the sources of these changes.

<table>
<thead>
<tr>
<th>Basin</th>
<th>2P at 30 Jun 2020</th>
<th>Sources of change in 2P Reserves</th>
<th>2P at 30 Jun 2021</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bowen</td>
<td>6,245</td>
<td>Produced 310 Extension - Net Acquisition 54</td>
<td>6,049</td>
<td>-3%</td>
</tr>
<tr>
<td>Surat</td>
<td>24,273</td>
<td>1,202 37 Reserve Upgrade 1,037 862</td>
<td>23,131</td>
<td>-5%</td>
</tr>
<tr>
<td>Cooper</td>
<td>1,064</td>
<td>104 - 4 97 49</td>
<td>1,003</td>
<td>-6%</td>
</tr>
<tr>
<td>Gippsland</td>
<td>2,140</td>
<td>297 177 44</td>
<td>1,968</td>
<td>-8%</td>
</tr>
<tr>
<td>Otway</td>
<td>571</td>
<td>33 178 42</td>
<td>655</td>
<td>15%</td>
</tr>
<tr>
<td>Bass</td>
<td>106</td>
<td>11 - 52 1 2</td>
<td>145</td>
<td>37%</td>
</tr>
<tr>
<td>Sydney</td>
<td>6</td>
<td>3 - 18</td>
<td>2</td>
<td>-58%</td>
</tr>
<tr>
<td>Gunnedah</td>
<td>13</td>
<td>1 - 3</td>
<td>15</td>
<td>15%</td>
</tr>
<tr>
<td>Amadeus</td>
<td>260</td>
<td>15 -</td>
<td>245</td>
<td>-6%</td>
</tr>
<tr>
<td>Total</td>
<td>34,677</td>
<td>1,978 92</td>
<td>33,213</td>
<td>-4%</td>
</tr>
</tbody>
</table>

Notes: 1. Totals may not add up due to rounding. 2. 2P at 30 Jun 2020 values differ from what we reported in our January 2021 interim report, due to the inclusion of Golden Beach’s 2P reserves and some minor differences between closing and opening values reported by suppliers.

As this table shows, 2P reserves fell in most basins over the last 12 months, with the only exceptions to this being:

- the Bass Basin where 2P reserves grew by 37% (39 PJ) over the period as a result of net acquisitions (i.e. acquisitions less disposals)

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185 2P reserves in 2017 were estimated to be 43,405 PJ. See ACCC, Gas Inquiry 2017–2020 Interim Report, December 2018, p. 52.


- the Otway Basin where 2P reserves grew by 15% (84 PJ) over the period, primarily as a result of Beach Energy’s Enterprise 1 discovery\(^{188}\)
- the Gunnedah Basin where 2P reserves grew by 15% (2 PJ) over the period, albeit from a relatively low base.

In contrast to these basins, 2P reserves fell across the Bowen, Surat, Cooper, Gippsland, Sydney and Amadeus basins. The decline in 2P reserves was greatest in the Surat Basin (1,142 PJ) because the additions to reserves were not sufficient to offset the production and reserve write-downs that occurred in this basin. \(^{189}\) The reserve write-downs and downward revisions were particularly pronounced in the Surat Basin, with 862 PJ of 2P reserves written down, predominantly in fields in which QGC\(^{190}\) and Arrow have an interest. A material portion of QGC’s reserve downgrades relate to a change in the economic cut-off (i.e. a reduction in the period over which reserves are assumed to be recovered). However, in contrast to fields in which QGC and Arrow have an interest, APLNG’s 2P reserves in a number of fields in the Surat Basin were upgraded.

The write-down in 2P reserves that has occurred in the Surat Basin over the last 12 months continues the trend that we have observed in Queensland over the last four years. During this period, there have been substantial volumes of 2P reserves downgraded to 2C resources or revised down for other reasons.

Arrow and QGC have accounted for the majority of these write-downs over the last four years. While APLNG has also written-down a relatively large volume of 2P reserves over the period, it has, as noted above, upgraded its 2P reserves across a number of fields in the Surat Basin in the last 12 months.

### A.5 Development of reserves and resources

Table A.4 sets out the development status of reserves and resources across the east coast and onshore Northern Territory.

As the bottom section of the table shows, over half of the 2P reserves (53%) in the east coast and onshore Northern Territory are currently undeveloped, with the majority located in Queensland. Further investment will be required to recover gas from undeveloped reserves. In contrast, gas from developed reserves is expected to be recovered from existing wells and facilities.

Having said that, a significant portion of these undeveloped reserves (79%) are located in fields that are either in production or approved for development. This means that producers have all the necessary approvals and have already made, or have committed to making, the investment in infrastructure required for production. This means development of these fields is either ready to begin or already under way. There is therefore a greater likelihood that gas from these fields will be produced in the medium term than there is for gas in fields that are not yet in production or not yet approved for development.

There are risks associated with the development of all gas reserves. However, the development of reserves in fields that are either in production or approved for development should be lower, meaning that there is more certainty of supply.

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\(^{189}\) The term ‘write-down’ is used in the appendix to jointly refer to reserves downgrades and other downward revisions. As noted in box A.1 the term ‘reserves downgrades’ refers to a reclassification of 2P reserves to either 3P reserves or contingent resources.

\(^{190}\) The reference to QGC in this context is used to refer to all participants in the QCLNG project (e.g. Tokyo Gas, CNOOC and QGC/Shell).
### Table A.4: Development status of reserves & resources, at 30 June 2021 (PJ)

<table>
<thead>
<tr>
<th>Reserves</th>
<th>Contingent Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>1P</td>
<td>2P</td>
</tr>
<tr>
<td><strong>Southern states (Gippsland, Otway, Bass, Gunnedah and Sydney basins)</strong></td>
<td></td>
</tr>
<tr>
<td>Developed</td>
<td>1,169</td>
</tr>
<tr>
<td>Undeveloped</td>
<td>Field in production</td>
</tr>
<tr>
<td></td>
<td>Approved for development</td>
</tr>
<tr>
<td></td>
<td>Other</td>
</tr>
<tr>
<td>Total</td>
<td>1,784</td>
</tr>
<tr>
<td>Developed % of Total</td>
<td>66%</td>
</tr>
<tr>
<td>Undeveloped % of Total</td>
<td>34%</td>
</tr>
</tbody>
</table>

| **Queensland (Bowen, Surat, Galilee and Clarence-Moreton basins)** | | | |
| Developed Reserves | 11,311 | 13,071 | 14,498 | - |
| Undeveloped Reserves and Resources | Field in production | 3,496 | 11,008 | 12,724 | 5,579 |
| | Approved for development | 23 | 1,697 | 1,733 | 530 |
| | Other | 23 | 3,404 | 6,171 | 18,670 |
| Total | 14,853 | 29,180 | 35,126 | 24,779 |
| Developed % of Total | 76% | 45% | 41% | 0% |
| Undeveloped % of Total | 24% | 55% | 59% | 100% |

| **Cooper (Cooper, Eromanga and Warburton basins)** | | | |
| Developed Reserves | 332 | 648 | 1,005 | - |
| Undeveloped Reserves and Resources | Field in production | 66 | 324 | 665 | 1,557 |
| | Approved for development | - | - | - | - |
| | Other | 12 | 30 | 79 | 355 |
| Total | 410 | 1,003 | 1,749 | 1,912 |
| Developed % of Total | 81% | 65% | 57% | 0% |
| Undeveloped % of Total | 19% | 35% | 43% | 100% |

| **Onshore NT (Amadeus and McArthur basins)** | | | |
| Developed Reserves | 132 | 184 | 233 | - |
| Undeveloped Reserves and Resources | Field in production | 56 | 61 | 77 | 196 |
| | Approved for development | - | - | - | - |
| | Other | - | - | - | 7,032 |
| Total | 188 | 245 | 310 | 7,228 |
| Developed % of Total | 70% | 75% | 75% | 0% |
| Undeveloped % of Total | 30% | 25% | 25% | 100% |

| **Total east coast and onshore NT** | | | |
| Developed | 12,944 | 15,745 | 17,983 | - |
| Undeveloped | Field in production | 4,101 | 12,064 | 14,344 | 7,639 |
| | Approved for development | 23 | 1,697 | 1,733 | 530 |
| | Other | 167 | 3,708 | 6,599 | 30,818 |
| Total | 17,235 | 33,213 | 40,659 | 38,986 |
| Developed % of Total | 75% | 47% | 44% | 0% |
| Undeveloped % of Total | 25% | 53% | 56% | 100% |

Source: ACCC analysis of data obtained from gas producers.

Note: Totals may not add up due to rounding.

Of the 3,708 PJ of undeveloped 2P reserves that are not yet approved for development in the east coast and onshore Northern Territory, over 90% are located in the Bowen and Surat basins, and the majority (85%) are held by the LNG producers, either through ownership or through purchases from other associated entities (i.e. Arrow Energy191 and Santos).

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While a decision is yet to be made to develop these reserves, a large number of producers indicated that they intend to make a final investment decision in the next two to three years. If they decide to proceed with the development, then supply from these fields could commence within the next five years. This accounts for around 69% (~2,614 PJ) of the undeveloped 2P reserves that are not yet approved for development. The remainder either expect supply to commence after 2026, or note that it is too speculative to state when supply could potentially commence.

In contrast to 2P reserves, the majority of 2C resources (~80%) are located in gas fields that are not yet in production or approved for development. The majority of these resources are located in CSG and other unconventional gas fields in the Bowen, McArthur, Galilee and Gunnedah basins. These resources face a range of technical, commercial and regulatory barriers. Therefore, it may take some time before these resources are considered commercially recoverable and capable of being supplied into the east coast market, if at all.

Some of the barriers to the commercial recovery of 2C resources that producers cited in their responses to the ACCC include:

- geological factors, such as the permeability, depth, and tightness of the reservoir and the level of impurities in the reservoir
- commercial factors, such as the relatively high development costs and access to the capital required to carry out appraisal activities and to develop the resources
- access to the infrastructure required to bring the gas to market (e.g. processing facilities and pipelines), which must either be developed as part of the project, or in those cases where there is existing infrastructure located in close proximity to the field, may be negotiated with the operators of these facilities
- land access, Indigenous Land Use Agreements, regulatory and environmental approvals.

Some producers also noted that joint venture arrangements can also act as a barrier to the development of 2C resources, if agreement to proceed with the development cannot be reached across all joint venture parties.
B. Approach to reporting on gas prices

This appendix sets out the ACCC’s approach to reporting on prices offered, bid and agreed to under GSAs, as presented in chapter 4.

B.1 Parameters of reported prices

The following apply to our analysis of prices reported in chapter 4:

- Prices reported are GST exclusive
- Prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user’s location or other ancillary charges (although delivery charges may, in some cases, be bundled with commodity gas prices). The prices charged for transportation have been excluded from our analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.
- Only arm’s length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Only those transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included.
- Where average prices are reported, these are quantity-weighted average prices. Where average prices are reported for a region, these are based on the location at which the gas is to be delivered rather than the location at which the gas is produced.
- The following entities were classified as ‘retailers’: Origin Energy, AGL, EnergyAustralia, ENGIE, Alinta Energy, Shell Energy Australia, Macquarie Bank and Weston Energy.

We note that prices of individual transactions are not necessarily directly comparable due to differences in non-price aspects such as flexibility, quantity, contract term and delivery point. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed. The ACCC has not sought to adjust for these factors in the analysis presented in chapter 4.

B.2 Reporting on offers and bids

The information in this section describes our approach to reporting on offers and bids, as presented in section 4.4 and should be read in conjunction with information above in section B.1.

The following also applies to our analysis of offers and bids.

- The analysis only includes those offers and bids that contain clear indications of price, quantity, supply start and supply end dates.
- The commodity gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil and LNG prices, foreign exchange rates and inflation) based on the expectations for those variables at the time of the offer or bid.\(^{192}\)

\(^{192}\) In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA)
- The expected Brent Crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg)
• Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  o For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2022) by taking a simple average of Brent crude oil prices expected in each month of that year.
  o We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  o We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.
• A similar approach is used to calculate an indicative price for offers and bids that specify a pricing mechanism linked to JKM (LNG) prices.

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

In sections 4.4.2 and 4.4.3 of this report, we compare prices offered (for those offers with fixed or JKM-linked pricing and a term of 1–3 years):
• for delivery in Queensland to expectations of LNG netback prices in Queensland and the estimated forward costs of production in Queensland in the month the offer or bid occurred
• for delivery in the southern states to the range of prices expected under a bargaining framework, outlined in previous ACCC reports, and the estimated forward costs of production in the southern states in the month the offer or bid occurred.

B.3.1 Approach to comparing offers in Queensland

We calculate LNG netback prices, based on Asian LNG spot prices, to compare against prices offered in Queensland (which is where the east coast gas market’s LNG export facilities are located).

Asian LNG spot markets provide an alternative for LNG producers to selling gas in the domestic market. As such, Asian LNG spot prices are likely to influence domestic gas prices under current market conditions. While LNG netback prices likely play an important role in the east coast gas market, they are not likely to be the sole factor influencing domestic prices.

The gas prices received by producers will also depend on the location of gas fields, the marginal cost of supply, the buyer’s maximum willingness to pay and the demand-supply balance, the importance of which will differ over time.

To calculate an LNG netback price to compare against offers for future supply, we have:
• calculated a forward-looking LNG netback price as at the date of the offer — based on market expectations of future LNG spot prices during the period of supply — as this gives the best indication of the likely opportunity cost of supplying gas to the domestic market193

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193  For this, we have used JKM futures prices (source: ICE).
used short-run incremental costs of LNG production and transport, since LNG producers are making decisions about the sale of excess gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC’s website, and which is described in detail in the ACCC’s Guide to the LNG netback price series.\(^{194}\)

The domestic offers analysed in sections 4.4.2 and 4.4.3 are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2021 as an example, we calculated an average 2021 LNG netback price that an LNG exporter would expect to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2021, and selling cargoes on the Asian LNG spot market in 2021.

For example, we calculated the average of LNG netback prices for 2021 that an LNG producer would have expected in July 2020 as follows:

- We obtained JKM futures prices for each month of 2021 that were quoted by ICE on each day during July 2020.
- We converted the monthly 2021 JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from USD$/MMBtu into AUD$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ
  - subtracting the short-run marginal costs of shipping, liquefaction\(^{195}\) and transportation\(^{196}\)
- We averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2021 expected on each day during July 2020.
- We then averaged these 2021 expectations for each day of July 2020 to arrive at an average of LNG netback prices for 2021 expected during the month of July 2020.

As has been noted before, our approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities. This is because these costs are sunk and do not influence the decisions of LNG producers, at the margin, to supply excess gas to the domestic or export markets.

Moreover, LNG spot prices are determined by short-run LNG market dynamics, such as LNG supply into spot markets, the level of competition, as well as demand and the ability for buyers to switch to alternative fuel sources (such as coal). These short-run dynamics are influenced by short-run supply, which in turn is determined by short-run incremental costs for the marginal supplier of LNG to spot markets (which are not influenced by the capital costs of building LNG export facilities).

There may be times, however, where LNG spot prices would be sufficiently high to allow LNG producers to recover apportioned capital costs (for their relevant LNG facility). There are also likely to be periods in which the opposite would be the case. Historically low spot prices in early 2020, which have been well below prices payable for LNG under long-term contracts, may not allow for recovery of capital costs. By some estimates, the long-run costs


\(^{195}\) We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG producers in Queensland.

\(^{196}\) We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.
of the Queensland LNG projects are above USD$10/MMBtu; well above current LNG spot prices.\textsuperscript{197}

\subsection*{B.3.2 Approach to comparing offers in the southern states}

Due to the cost of transportation between the southern states and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the southern states, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user’s location
- the seller alternative (representing a floor in negotiations) – the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher).

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

The supply-demand outlook in the southern states is particularly important to the outcome. If there are limited supply options for gas users in the southern states, such as in the case of an expected gas supply shortfall, users that are unable to reach an agreement for gas supply with a southern supplier will need to transport gas from Queensland. In this scenario, gas suppliers in the southern states would be expected to offer a buyer alternative price in every region in the southern states.

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things equal. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location. Therefore, the buyer’s alternative price in Victoria is indicative of the maximum price that would be likely to prevail in a well-functioning market.

Conversely, if there were sufficient supply and diversity of suppliers in the southern states, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the southern states rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the ‘seller alternative’ price. In this scenario, the prices offered by suppliers in the southern states would be lower the further away the source of supply is from Queensland, but not below the forward cost of production. The forward cost of production therefore sets the floor price in any gas supply negotiation.

To meaningfully analyse the level of prices offered in a particular location in the southern states using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the analysis in chapter 2 we present a buyer and seller alternative for Victoria.

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

\textsuperscript{197} Ferrier Hodgson, National Resources Insights, 2017
B.3.3  Forward costs of production

In 2018, we engaged Core Energy (Core) to develop detailed estimates of the gas production costs facing producers in the east coast gas market. For individual supply regions across the east coast, Core estimated both full lifecycle costs of production and forward costs of production for 2P reserves as at 31 December 2017.\(^{198}\)

The analysis in sections 4.4.2 and 4.4.3 compares price offers for 2022 and 2021 supply with estimates of forward production costs, since over the short-term producers are likely to continue producing gas as long as they expect to recover their operating costs.

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

For Queensland, we chose the Middle Surat and Roma Shelf supply region as it has material uncontracted 2P reserves (9,260 PJ) that Core expected to commence production by 2020 and that Core estimated to have the highest forward cost ($5.55/GJ).

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

It is difficult to predict what the new source of supply would be or what the forward production cost of the marginal supplier is likely to be. For the purpose of the analysis in chapter 4, we have chosen the Sole gas field as a proxy for the costs of a new marginal supplier. The Sole field is a new source of production in the south and its costs are therefore indicative of the likely costs of a new supplier. According to Core’s estimates, Sole had 249 PJ of 2P reserves with an estimated forward production cost of $5.60/GJ as at 31 December 2017.\(^{199}\)

B.4.  Reporting on GSA pricing and flexibility

The information in this section describes our approach to reporting on GSAs, as presented in section 4.5.1 should be read in conjunction with information above in section B.1.

The following also applies to our analysis of GSAs:

- For the purpose of the analysis of producer prices, we have included GSAs executed at arm’s length by producers with all counterparties. For the purpose of the analysis of retailer prices, we have only included GSAs between retailers and C&I users. Analysis may also include price amendments.


\(^{199}\) We intend to update the assumptions and costs estimates for future reports using data published by AEMO on production costs in the east coast gas market.
We estimated prices payable using recent expectations of key variables, including, where relevant, the AUD/USD foreign exchange rate, inflation, Brent Crude oil and JKM. To estimate the price payable in a given supply year, we have taken the simple average of expected prices in each supply month in that year.

We also report on the average load factor and take or pay multiplier in section 4.5.2. Both the load factor and the take-or-pay multiplier are measures of the level of flexibility allowed under the contract. Specifically:

- The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. The higher the load factor, the more gas a gas user can take on a given day above their average daily allowance.

- The take-or-pay multiplier is the percentage of the contracted gas that must be paid for by the buyer whether or not the buyer actually takes delivery of the gas. A GSA with a take-or-pay multiplier of 100% implies that the buyer has to pay for all of the gas it has contracted to take, irrespective of whether it uses the gas in the year. A GSA with a take or pay multiplier of 0% is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

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200 This differs to our approach to reporting on prices offered and bid, in which we estimate prices based on expectations in the month the offer or bid occurred.