Narrabri Gas Project and the Northern NSW Inland Port

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Pegasus Economics is a boutique economics and public policy consultancy firm that specialises in strategy and policy advice, economic analysis, trade practices, competition policy, regulatory instruments, accounting, financial management and organisation development.

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Photograph on the front cover is from coal seam gas wastewater processing infrastructure in the Pilliga Forest – image from the film, Pilliga Rising. Credit | Mark Pearce.

Table of Contents

Executive Summary

Introduction

- Lock the Gate has commissioned Pegasus Economics (Pegasus) to undertake an economic analysis of the use of coal seam gas (CSG) from the Narrabri Gas Project (NGP) being developed by Santos to the proposed Northern NSW Inland Port (N2IP) for industrial users.
- The report highlights Santos' problematic role in the Eastern Gas Region and associated gas markets, the volatility of gas prices and the risks that poses to participants in the N2IP, and assesses the renewable energy opportunities in the region that could form an alternative basis for industrial activity.
- The Narrabri Shire Council is intending to develop the N2IP as a logistics and industrial hub on a significant area of land located adjacent to the intersection of the Narrabri West Walgett Railway line and the proposed Inland Rail corridor (Dawson E. , 2020, p. 27).
- Narrabri was announced as a Special Activation Precinct (SAP) by the NSW Government in November 2020 (NSW Department of Planning and Environment, 2022). The investigation area for the Narrabri SAP is in the same vicinity as the proposed N2IP, around 7 km from the town centre around Yarrie Lake Road, and comprises of approximately 2,160 hectares (NSW Department of Planning and Environment, 2021).
- It is envisaged that the NGP will be able to attract energy intensive industries and value-added manufacturing to the Narrabri SAP (NSW Department of Planning and Environment, 2021). Similarly, it is intended that would-be participants in the N2IP project will be able to leverage off the potential supply of gas from the NGP.

Gas prices and the domestic gas market

- Estimated production costs for the NGP have been put at around $7.90 per gigajoule (GJ) (Fowler, 2020), placing it at the expensive end of gas production.
- There are currently 9 other developed and undeveloped gas projects in Australia with lower estimated production costs than the NGP (Australian Energy Market Operator, 2022a). These 9 developed and undeveloped gas projects with estimated lower production costs represent in excess of 49,000 petajoules (PJ) in terms of natural gas resources.
- Not only does NGP have higher production costs, but Santos has also played a key role in driving up gas prices in the Eastern Gas Region.
- Located in the Eastern Gas Region at Curtis Island near Gladstone in Queensland, there are now three liquid natural gas (LNG) export projects. In 2021 LNG exports accounted for around 71.8% of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2022a).
- In 2016 the Santos-led Gladstone LNG (GLNG) project began purchasing substantial volumes of gas in the domestic market to supplement production from its inadequate gas reserves (Australian Competition and Consumer Commission, 2016, p. 24). In particular, Santos diverted gas from the Cooper Basin that historically had supplied NSW and South Australia. In turn, wholesale gas prices offered to domestic users began to rise.
- With the commencement of LNG exports in early 2015, the Eastern Gas Region was transformed from a captive domestic "buyer's" market to an internationally-linked "seller's" market (Forcey & McConnell, 2017, p. 12). Since 2015-16, gas prices have more than tripled in the Eastern Gas Region.
- On an aggregate basis, the LNG exporters and their associates were responsible for 77% of gas production in the Eastern Gas Region during 2020-21 (Australian Competition and Consumer Commission, 2022a). The LNG exporters and their associates also had influence over close to 90% of the proven plus probable (2P) gas reserves in the east coast in 2021,

through a combination of their direct interests in 2P reserves, joint venture and exclusivity arrangements (Australian Competition and Consumer Commission, 2022a, p. 6).

- Contracted gas prices have been quoted as high as $30 per GJ during October 2022 (Macdonald-Smith & Fowler, 2022) while wholesale spot prices exceeded $40 per GJ during the winter of 2022 (Australian Energy Regulator, 2022, p. 5).
- Arguably, the LNG exporters are abusing their market power and behaving as a *de facto* cartel, deliberately withholding and withdrawing gas from the Eastern Gas Region, thereby raising gas prices. In turn, this has implications for the demand and supply balance in the Eastern Gas Region.
- Ongoing and persistently high gas prices for domestic users in the Eastern Gas Region is likely to lead to demand destruction. Contrary to a normal supply and demand cycle, demand destruction occurs when persistent high prices or limited supply for a product reduces demand leading to a *permanent, widespread abandonment* of the product (DTN Team, 2022).
- Continued high prices in the Eastern Gas Region are likely to lead to demand destruction as industrial users and gas-powered generators (GPG) seek alternatives to gas supply or simply cease operations, including prospective participants in the N2IP.

Climate Change Policy and Stranded Asset Risks

- Methane, the largest component of processed natural gas, is classified as a greenhouse gas (GHG), so its presence in the atmosphere affects the earth's temperature and climate system (U.S. Environmental Protection Agency, 2022).
- Parties to the 2015 Paris Agreement pledged to limit global warming to well below 2°C and to pursue efforts to limit the temperature increase to 1.5°C relative to pre-industrial times (Welsby, Price, Pye, & Ekins, 2021, p. 230).
- The Albanese Commonwealth Government elected in May 2022 has committed to reducing Australia's greenhouse gas emissions by 43% by 2030 – which will become Australia's target under the Paris Agreement, keeping Australia on track to achieve net zero by 2050 (Australian Labor Party, 2021).
- Furthermore, under the Albanese Commonwealth Government Australia joined the Global Methane Pledge in October 2022, a voluntary commitment with 122 signatories including the United States, United Kingdom and the European Union working collectively to reduce global methane emissions across all sectors by at least 30% below 2020 levels by 2030 (Bowen, 2022).
- Stranded assets are defined as assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities (Caldecott, Dericks, Pfeiffer, & Astudillo, 2017, p. 04).
- Stranded assets include physical (e.g., fossil fuel equipment, infrastructure), financial (e.g. equity and debt); natural (e.g. fossil fuel resources); human (e.g. expertise, jobs); and social (e.g. networks and communities) assets (Rempel & Gupta, 2021).
  - If physical stranded assets are decommissioned prematurely, then financial stranded assets would subsequently arise as revenues are lost and debts/equity remain on balance sheets; dependent jobs would be stranded (human assets) and communities dismantled (social assets), in addition to the resources themselves that potentially are no longer viable for commercialisation (natural assets).
- In recent years, the issue of stranded assets caused by environmental factors, such as climate change and society's attitudes towards it, has become increasingly high profile (Caldecott, Dericks, Pfeiffer, & Astudillo, 2017, p. 04).
- Several factors could lead to assets becoming stranded (Matikainen & Soubeyran, 2022). These include: new government regulations that limit the use of fossil fuels and carbon

dioxide emissions; and a change in demand, such as a shift towards renewable energy because of lower energy costs.

- Moving forward, the risks of fossil fuel asset stranding could come from improvements in energy efficiency, as well as advancements in renewables and battery storage (Paun, Knight, & Chan, 2015, p. 1).
- Thus, new natural gas projects such as the NGP run the risk of becoming stranded due to regulatory requirements that constrain carbon dioxide emissions as well as improvements in alternative energy technology.
- Companies extracting oil, gas, and coal could be affected by stranded assets as a result of the low-carbon dioxide transition, but it is not only the fossil fuel sector that is at risk (Matikainen & Soubeyran, 2022). Other sectors that use fossil fuels as inputs for production or are otherwise energy – or carbon dioxide-intensive, could also be impacted. As the world transitions away from high-carbon dioxide emitting activities, all technologies and investments that cannot be adapted to low-carbon dioxide and zero-emission modes could face stranding.
- In turn, developing the N2IP and a Special Activation Precinct (SAP) predicated on natural gas supply from the NGP exposes participants dependent upon gas to the heightened risk of having their assets stranded as well.

Specific projects proposed at N2IP

- So far, Santos has entered into tentative supply arrangements with three potential manufacturers who may also participate in the N2IP.

Perdaman Fertiliser/Explosives Plant

- In late February 2019, Santos (2019a) announced that it had entered into a non-binding agreement with Perdaman for the supply of 14.5 PJ of natural gas per annum over 20 years, subject to a final investment decision for the NGP. Under the agreement, gas would be supplied to a proposed new ammonium nitrate plant near Narrabri to produce fertiliser for agribusiness.
- Globally, ammonium nitrate is largely used in the manufacture of nitrogen-based fertilisers (Australian Competition and Consumer Commission, 2011, p. 6). However, the use of ammonium nitratre as a fertiliser in Australia has been significantly restricted by regulation related to national security.
- While ammonium nitrate can be used as a fertiliser in agricultural applications, the market for this application in Australia is relatively small (John O'Connor and Associates Pty Ltd, 2018, p. 13).
- Demand for ammonium nitrate in Australia is driven by mining companies seeking to extract beneficial ores (i.e. iron and coal) from the earth (John O'Connor and Associates Pty Ltd, 2018, p. 13).
- Ammonium nitrate production facilities are located close to the main mining areas of the Sydney and Gunnedah basins in NSW, the Bowen Basin in Queensland, the Kalgoorlie region of Western Australia and, more recently, the Pilbara region in Western Australia.
- Given the restrictions imposed on ammonium nitrate in Australia by regulation, and the fact that this substance is primarily used in the manufacture of explosives rather than fertiliser, claims made by Perdaman and Santos that the Perdaman ammonium nitrate facility will exclusively manufacture fertiliser for Australian agriculture should be treated with extreme caution. It is far more likely that Perdaman is intending to build an explosives manufacturing facility at Narrabri to service the mining industry, rather than focus on the production of nitrogen-based fertilisers.
- Rather than produce ammonium nitrate for the production of fertilisers, it appears that Perdaman is more likely to be producing ammonium nitrate for the manufacture of

explosives and would target coal mining operating in the Sydney and Gunnedah basins as its prospective customer base.

- A combination of excess capacity on the east coast of Australia and declining demand for ammonium nitrate explosives in the Sydney and Gunnedah basins, high barriers to entry in relation to substantial sunk costs, and the need to lock in long term supply contracts makes the Perdaman proposal an extremely high-risk commercial proposition. The Perdaman proposal appears to be so fantastic that it is bordering on a hoax.
- Perdaman could pursue its ammonium nitrate facility by producing green ammonium that employs renewable, rather than fossil fuel sourced hydrogen at Narrabri, although the availability of water could be a limiting factor.

Brickworks Brick Factory

- In May 2019 Santos (2019c) announced that it had signed a non-binding memoranda of understanding with Brickworks for the supply of natural gas from the NGP.
- Brickworks uses natural gas to fire kilns to dry bricks.
    - The final stage in the industrial production of bricks is for them to be fired in a kiln between 10 and 40 hours, depending upon kiln type and other variables (The Brick Industry Association, 2006, p. 4). Fuel used to fire the kiln may be natural gas, coal, sawdust, methane gas from landfills or a combination of these fuels.
- In September 2018 Brickworks signed a long-term natural gas supply agreement with Santos (2018) for it to supply its east coast operations through to the end of 2024.
- In June 2022 it was reported that Brickworks contract gas price with Santos was averaging $10 per GJ, locked in for two years, compared with the then government-mandated price cap of $40 (Kaye, 2022). According to Brickworks' Managing Director Lindsay Partridge at the time:

    If we had to pay, when our contract rolled over, (the current spot price), we would no doubt be shutting plants down and moving production offshore. (Kaye, 2022)

- In the current environment with soaring gas prices, it is unlikely that Brickworks would be rushing to sign a new gas supply agreement for NGP gas any time soon.
- During 2021-22, alternative biofuels made up 12% of Brickworks' Australian energy mix and the company continues to investigate ways to increase its biofuels content (Brickworks Ltd, 2022, p. 56).
- It is entirely possible that a new Brickworks brick factory could operate at N2IP in the absence of the NGP, providing it has access to alternative fuel sources such as methane gas from landfills or sawdust. Given prevailing prices for natural gas, biofuels become an increasingly attractive and viable proposition.

Natural Soda Baking Soda Factory

- The Water Expert Panel established to advise on water issues related to the NGP considered that salt waste production from the project could be up to approximately 850,000 tonnes over the project life (Cook, Carter, Fell, & Williams, 2020, p. 79).
- The 33,600 tonnes a year of salt waste from the NGP is a source of angst for locals and experts without a formal plan to dispose of it (Macdonald-Smith & Fowler, 2020).
- In order to address those concerns, in July 2020 Santos (2020b) signed a Memorandum of Understanding (MOU) with Natural Soda to use salt removed from produced water as part of the NGP. Santos and Natural Soda committed to undertaking a concept study to produce sodium bicarbonate in Narrabri.
- However, scientists have argued this MOU should not be seen as enough to assuage concerns that the salt could lead to dangerous contamination of ground and surface water (Moreton, 2020).

- According to Mark Ogge (2020, p. 26) from *The Australia Institute*:

> *The idea of a baking soda factory using (toxic) waste salt from coal seams is little more than a thought bubble. If such a venture was viable there should already be baking soda factories attached to coal seam gas fields all over Queensland.*

- The idea of taking salt waste from CSG production and turning it into useful salt products is not new. Selective salt recovery (SSR) is a unique combination of existing technologies to produce salt products from brine for potential beneficial reuse (Australian Petroleum Production and Exploration Association, 2018, p. 49).
- In December 2018 the Australian Petroleum Production and Exploration Association (APPEA) (2018), the industry body representing Australia's oil and gas explorers and producers, published a report on waste water issues related to the Queensland CSG industry. This report determined SSR was infeasible due to a lack of suitable technology at a commercial scale, high upfront and lifecycle costs, significant energy consumption requirements and low excess demand in the current market (Department of Environment and Science, 2021, p. 1).
- The construction of a baking soda factory at the N2IP is entirely dependent on the NGP proceeding. However, even if the NGP were to proceed, it is uncertain that a baking soda factory would prove to be commercially viable and proceed in any event. Processing salt waste from the CSG industry has previously been considered, trialled and failed as a commercial proposition.

1. Introduction

Lock the Gate has commissioned Pegasus Economics (Pegasus) to undertake an economic analysis of the use of gas from the Narrabri Gas Project (NGP) to the proposed Northern NSW Inland Port (N2IP) for industrial users.

The views and opinions expressed in this report are entirely those of the author.

An outline on the natural gas industry is provided in Appendix 1 below.

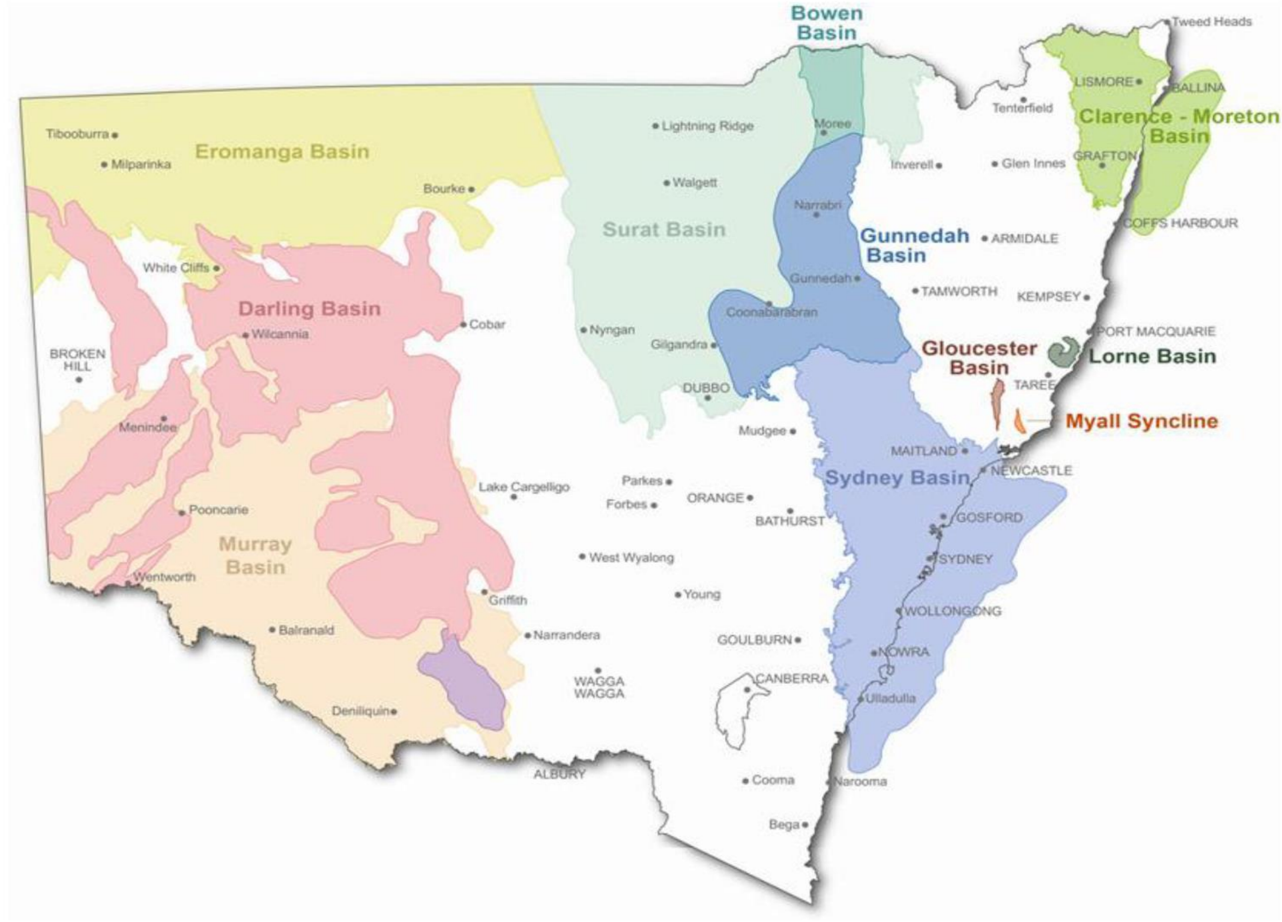
2. Narrabri Gas Project and Associated Developments

2.1 Gunnedah Basin

The Gunnedah Basin is a structural trough in northeast New South Wales (NSW) (O'Kane, 2013, p. 43). The basin appears continuous with the Bowen Basin in the north and the Sydney Basin in the south. The Great Artesian Basin overlies the Gunnedah Basin. The Gunnedah Basin covers an area of approximately 15,000 km^2 (Welsh, et al., 2014, p. 37).

A map of the Gunnedah Basin along with other NSW sedimentary basins is provided below in Figure 1.

Figure 1: New South Wales Sedimentary Basins



Sources: O'Kane (2013, p. 42) taken from (NSW Division of Resources and Energy (Cartographer), 2013).

Several areas of the Gunnedah Basin have been indicated as having potential for coal seam gas (CSG) resources (O'Kane, 2013, p. 43).

2.2 Gas Resources in the Gunnedah Basin

Reserves are those quantities of natural gas anticipated to be commercially recoverable by a project from known accumulations from a given date forward (Society of Petroleum Engineers, 2018, p. 3). Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining. Reserves are most commonly reported at the proven plus probable reserves or 2P level which refers to the best estimate (Society of Petroleum Engineers, 2018, p. 37). The best estimate represents that there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate (Society of Petroleum Engineers, 2018, p. 12).

Natural gas can also be reported as contingent and prospective resources. Contingent resources are quantities of natural gas estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of a project not currently considered to be commercially viable due to one or more contingencies (Society of Petroleum Engineers, 2018, p. 3). Contingent resources are commonly reported on a 2C basis which refers to the best estimate of contingent resources (Society of Petroleum Engineers, 2018, p. 37).

Prospective resources are those quantities of natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects (Society of Petroleum Engineers, 2018, p. 3). Prospective resources are commonly reported on a 2U basis which refers to the unrisked best estimate qualifying as prospective resources.

There are significant variations between estimates of available gas resources in the Gunnedah Basin. The Australian Energy Market Operator (AEMO) (2020) reported contingent resources (2C) of 971 petajoules (PJ) and prospective resources (2U) of 3,502 PJ in Gunnedah Basin in 2020 based on material provided by the Core Energy Group.[1] In February 2016 Santos (2016) downgraded its proven plus probable (2P) reserves in the Gunnedah Basin as contingent resources and hasn't provided any public update since. Grossing up the Santos share of the NGP at that time to account for the entire project provides an estimate of contingent resources in the Gunnedah Basin consistent with the level of 2C resources reported by the AEMO.

The AEMO (2021) reported reserves (2P) of 728 PJ and prospective resources (2C) of 463 PJ in the Gunnedah Basin based on material provided by energy consultants Wood MacKenzie. The AEMO did not publish separate estimates of gas resources in the Gunnedah Basin in 2022.

Grant Samuel & Associates Pty Limited (Grant Samuel) (2021, p. 82) has estimated combined 2P and 2C gas resources of almost 1,744 PJ in the Gunnedah Basin that could be based on confidential information provided by Santos.

Based on data provided by gas producers, the Australian Competition and Consumer Commission (ACCC) (2022, p. 159). has reported reserves (2P) of 15 PJ and contingent resources (2C) of 2,561 PJ in the Gunnedah Basin. Specifically in relation to the NGP, the ACCC has reported the project has gas reserves (2P) of 13 PJ and contingent resources (2C) of 1,798 PJ.

Differing estimates of the available gas resources in Gunnedah Basin are provided in Table 1 below.

[1] A petajoule is a unit of energy used for expressing the energy content of fuels.

Table 1: Estimates of Gas Resources in the Gunnedah Basin (PJ)

Resource category	Santos	Core Energy Group	Wood Mackenzie	Grant Samuel	ACCC
Reserves (2P)			728		15
Contingent resources (2C)	971	971	463	1,798*	2,562
Prospective resources (2U)		3,502			

Sources: AEMO (2020; 2021), Santos (2015; 2016), Grant Samuel (2021, p. 82), and ACCC (2022, p. 159).
* Includes combined 2P and 2C gas resources.

2.3 Narrabri Gas Project Development

The NGP proposes to extract natural gas resources from CSG about 20 km south-west of the town of Narrabri in the central portion of the Gunnedah Basin (GHD, 2017).

The NGP has been proposed by Santos NSW (Eastern) Pty Ltd, a wholly owned subsidiary of Santos Ltd (Santos), an Australian oil and gas company listed on the Australian Securities Exchange. On 22 December 2021 Santos (2022) acquired the remaining 20% interest in the Narrabri assets.

The project area contains a portion of the Pilliga Forest, with the majority of the project located on Crown land (GHD, 2017, p. 1.1). The Pilliga Forest is an agglomeration of forested areas covering more than 500,00 hectares around Coonabarabran, Baradine and Narrabri. The majority of native vegetation on more productive soils in the surrounding area has been cleared for agriculture, with the Pilliga Forest left as a large dry woodland remnant on the poorest sandy soils (Murphy & Murphy, 2015, p. 517). The landform of the Pilliga Forest ranges from low sandstone hills and broad sandy valleys in the south-east to a flat outwash sand plain in the west and north. The NGP covers the Pilliga north of Coonabarabran and the eastern part of the Pilliga outwash, and bordering the northern end of the Liverpool Plains (Herr, et al., 2018, p. 12). The Liverpool Plains supports highly valuable agricultural development including cropping of cotton and grains, with the less arable soils being under livestock grazing (Herr, et al., 2018, p. 10).

The NGP would include the progressive installation of up to 850 new gas wells on up to 425 new well pads over approximately 20 years and the construction and operation of gas processing and water treatment facilities (GHD, 2017, p. ES.1).[2]

For the NGP the natural gas from coal seams will be reached by drilling a gas well through overlying rock strata until it reaches the target coal seam (GHD, 2017, p. ES.2). The coal seams are predominantly located between 500 and 1,200 metres underground below the surface aquifers including the Great Artesian Basin. The geology within the project area lends itself to the use of lateral and incline drilling techniques to release the gas, therefore fracking is not proposed to be used for the project.

Small amounts of CSG are currently being generated from the NGP exploration wells to supply gas to the Wilga Park Power Station (General Purpose Standing Committee No. 5., 2012, p. 11).

[2] The first stage in the life cycle of a well once a location has been selected is to prepare a well pad for drilling (Huddlestone-Holmes, Measham, Jeanneret, & Kear, 2018, p. 4). Well pads are typically 1 to 1.5 hectares in area and provide the working area for drilling operations. They are usually prepared using earthworks machinery to level the site and clear vegetation. Aggregate may be laid down to allow all-weather access and operations of the drill rig. Topsoil is stockpiled at the site so that it can be put back in place during rehabilitation of the site. The well pad may have one or two sumps to store water, catch drill cuttings and hold drilling mud during operations. These sumps have a capacity of around 100,000 litres. The well may also have a flare pit to contain ground flares that allow for the controlled burning of gas from the well.

The NSW Independent Planning Commission (2020) granted a phased approval for the NGP that is subject to stringent conditions, which means that Santos must meet specific requirements before the NGP can progress to the next phase of development. The four phases of development are: 1) appraisal; 2) construction; 3) production; 4) rehabilitation. The NGP received regulatory approval from the then Commonwealth Environment Minister Susan Ley in late November 2020 (Santos Ltd, 2020).

In August 2022 Santos (2022b) acquired the Hunter Gas Pipeline project, an approved underground gas pipeline route from Wallumbilla in Queensland to Newcastle in NSW. According to Santos, the acquisition of the Hunter Gas Pipeline project is an important step for the NGP as it will "get Narrabri gas to domestic market as soon as possible."

At the time it received regulatory approval from the Commonwealth Environment Minister, Santos (2020) commented that it "will now embark on a 12-18 month appraisal program ahead of a Final Investment Decision (FID) for the next phase of project development." Following its decision to acquire the Hunter Gas Pipeline project, Santos (2022b) said that it was intending to conduct appraisal drilling later 2022, pending various native title and environmental management plan approvals. Santos is still yet to announce a final investment decision in relation to the NGP.

2.4 Narrabri Gas Project Environmental Infractions

In July 2012 the NSW Environment Protection Authority (EPA) (2012) issued Eastern Star Gas, the former operator of the NGP, with two penalties and fines of $3,000 for discharging polluted water to Bohena Creek in the Pilliga Forest. In February 2014 the EPA (2014) issued a $1,500 fine to Santos NSW (Eastern) Pty Ltd following a pollution incident at their Narrabri Gas Field operations in the Pilliga. In May 2015 the EPA (2015a) completed investigations into two separate incidents that occurred at the NGP in 2013 and 2015. Although the investigations showed that neither of these incidents resulted in any significant environment impacts, the EPA did express concerns with aspects of the site operations and management.

2.5 Narrabri Gas Project Production and Delivery Costs

It is claimed the NGP has the capacity to deliver up to 200 terajoules (TJ) of gas per day (GHD, 2017, p. 1.11). This converts to an annualised figure of 73 PJ. It was claimed in the Preliminary Environmental Assessment that the project would have the capacity to produce approximately 70 PJ of gas per annum (GHD, 2014, p. 19). In the economic assessment of the NGP on behalf of Santos, GHD (2016, p. 13) assumed that production would start at 12.8 PJ per annum in 2020 and increase to 74.1 PJ in 2025 from where production would plateau and then eventually tail off, falling to 55 PJ by 2041 (GHD, 2016, p. 19).

Based on a production capacity of up to 200 TJ of gas per day, it has been claimed that the NGP could supply up to 50% of current gas demand for NSW based on gas consumption of 138 PJ in 2013 (GHD, 2014, p. 19). Based on current estimated NSW gas consumption of almost 114 PJ in 2021, this amounts to around 64% of current NSW gas consumption.

In its 2019 Gas Statement of Opportunities report for eastern and south-eastern Australia, the AEMO (2019) published estimates of natural gas resources and estimates of production costs for both developed and undeveloped gas projects with data sourced from Core Energy & Resources and gas industry participants. This suggested the NGP was a relatively high- cost gas development project with an estimated production cost of $7.40 per gigajoule (GJ), ranking 41 out of 51 actual and undeveloped gas projects from lowest to highest in terms of production costs.[3]

In the preparation for the 2020 Gas Statement of Opportunities report, the AEMO commissioned Core Energy & Resources (2019, p. 7) to develop an estimate of the cost of production of reserves

[3] One petajoule is equal to one million gigajoules.

and contingent resources as of 31 December 2018. While Core Energy & Resources on this occasion did not provide a precise figure for the estimated production cost of gas from the Gunnedah Basin, it provided a range of estimated production costs of between $6.77 to $9.87 per GJ depending on what components were to be included as part of the cost base.

In its 2020 Gas Statement of Opportunities report, the AEMO (2020) provided an updated estimate for production costs at the NGP of $6.40 per GJ based on Santos' P50 production cost at the gate (post processing). This presumably followed representations made by Santos (2020a, p. 3) to the AEMO. Estimates of production costs for the NGP provided in more recent Gas Statement of Opportunities reports are consistent with the 2020 report.[4]

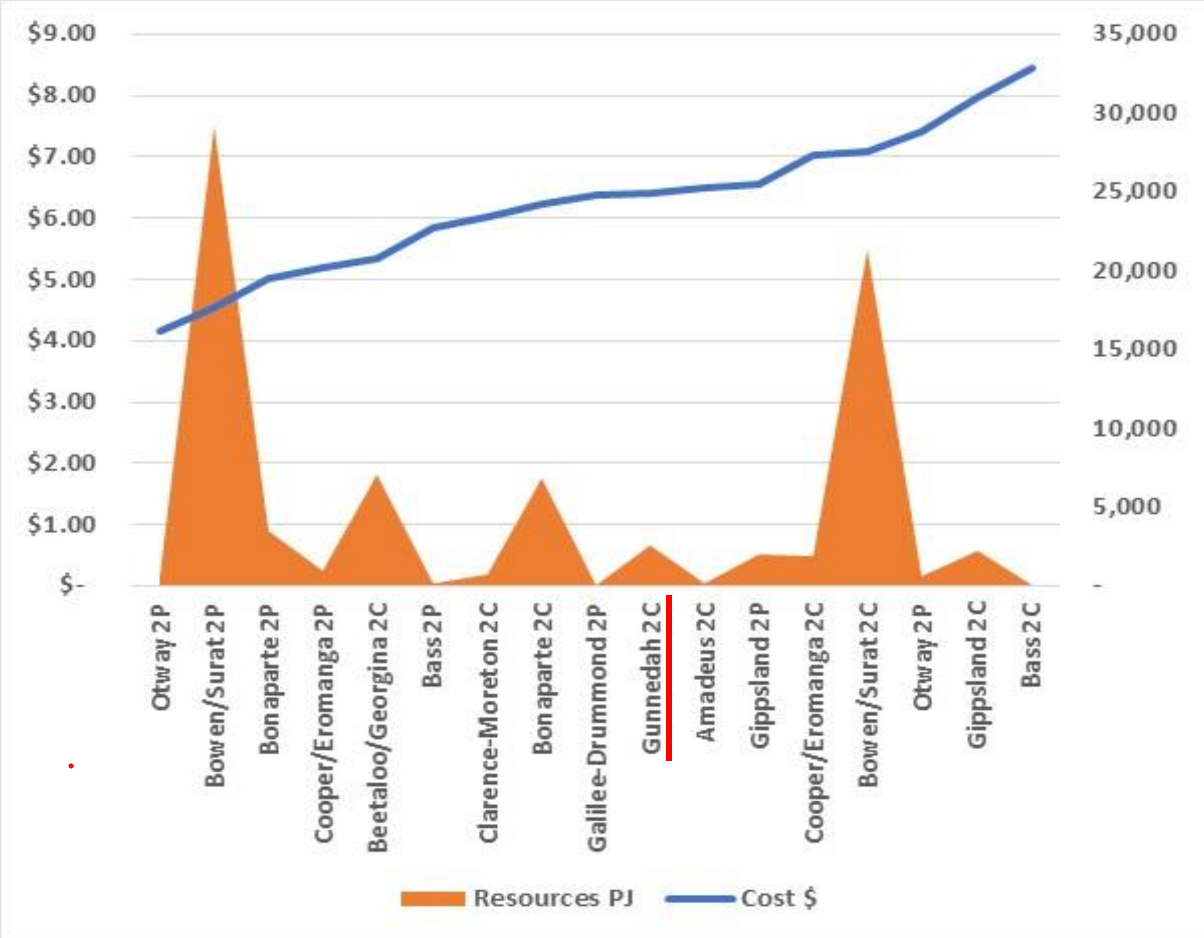
In 2020 Santos had said that it had factored in a cost of production of $7.90 per GJ for the project, including the $1.50 pipeline tariff (Fowler, 2020).

In relative terms, the development of gas resources in the Gunnedah Basin ranks 10 out of 17 actual and undeveloped gas projects in terms of production costs.

There are 9 developed and undeveloped gas projects with lower estimated production costs than the production of CSG in the Gunnedah Basin. These 9 developed and undeveloped gas projects with estimated lower production costs represent in excess of 49,000 PJ of 2P and 2C natural gas resources. The estimate of production costs and gas resources for both developed and undeveloped gas projects is provided in Figure 2 below, whereby the estimated production costs for each project provides an effective gas supply curve for the Eastern Gas Region.

[4] See AEMO (2021; 2022a).

*Figure 2: Estimated Supply Curve for Developed and Undeveloped Gas Project (2021 $/GJ real) and Estimated 2P and 2C Gas Resources for the Eastern Gas Region (PJ)**



Sources: Production costs taken from AEMO (2022a), 2P reserves and 2C contingent resources taken from ACCC (2022, p. 159), except for the Bonaparte Basin that comes from AEMO (2022a).
* Note: Production costs from the Sydney Basin have been excluded as the Camden Gas Project is due to cease production in 2023. Production costs are the marginal cost of production a GJ of sales gas to the point of sale into a transmission pipeline and thus excludes transport costs. Costs include operating costs, capital costs, royalty, tax and a return on capital.

2.6 Northern NSW Inland Port (N2IP)

The Narrabri Shire Council (2020, p. 60) is intending to develop the Northern NSW Inland Port (N2IP) project. The N2IP is the proposed development of a logistics and industrial hub on a significant area of land located adjacent to the intersection of the Narrabri West Walgett Railway line and the proposed Inland Rail corridor (Dawson E. , 2020, p. 27). Inland Rail is a railway construction project that will divert rail freight travelling from Melbourne to Brisbane out of the congested Sydney network.

Narrabri was announced as a Special Activation Precinct (SAP) by the NSW Government in November 2020 (NSW Department of Planning and Environment, 2022). SAPs are unique to regional NSW and seek to provide business investors with streamlined planning and environmental approvals processes in order to create jobs and boost economic growth in dedicated regional locations across NSW (NSW Department of Planning and Environment, 2022a). The investigation area for the Narrabri SAP is in the same vicinity as the proposed N2IP, around 7 km from the town centre around Yarrie Lake Road, and comprises of approximately 2,160 hectares (NSW Department of Planning and Environment, 2021). The SAP will plan for access to suitably zoned land, government funding for enabling infrastructure, and streamlined planning approvals which will provide incentive for national and international businesses to establish and operate more efficiently. The Narrabri SAP will seek to leverage key infrastructure such as the Inland Rail and the N2IP, giving investors direct access to global supply chains and markets.

The N2IP will provide investment opportunities for transport and logistics operators, manufacturers, agri-businesses and service providers, and offer a competitive advantage to businesses requiring national and global distribution (Narrabri Shire Council, 2020a, p. 2). The N2IP will feature a freight and logistics terminal with access to Inland Rail, as well as an industrial park with all of the enabling infrastructure required to support business operations. The N2IP site will be zoned industrial/special purpose to enable the attraction and development of the widest variety of industrial and commercial businesses (Narrabri Shire Council, 2020a, p. 2).

It is envisaged that the NGP will be able to attract energy intensive industries and value-added manufacturing to the Narrabri SAP (NSW Department of Planning and Environment, 2021). Similarly, it is intended that would-be participants in the N2IP project will be able to leverage off the potential supply of gas from the NGP. According to the prospectus for the N2IP:

> *Existing local and new businesses wanting to access commercial quantities of gas will benefit from the industries innovative production and connection costs. (Narrabri Shire Council, 2020a, p. 2)*

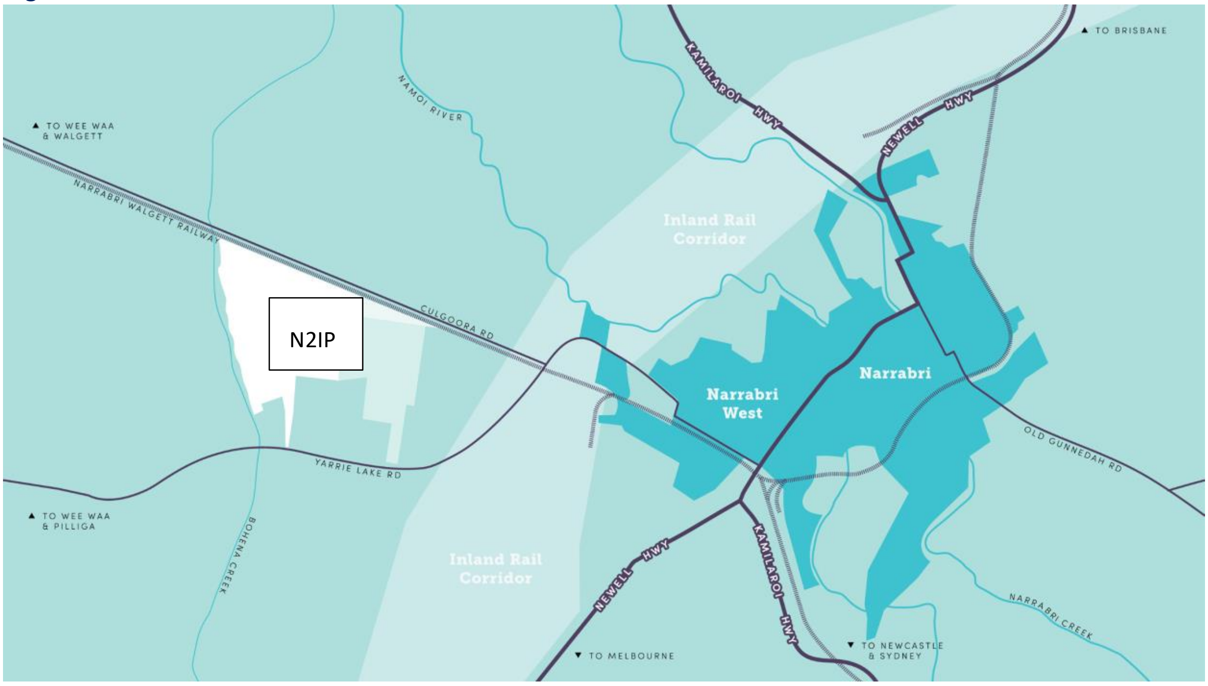
The Strategic Business Case for the N2IP project indicated that development of the site would be likely to directly result in up to 900 full times jobs (Narrabri Shire Council, 2020, p. 60). Flow on effects for the economy of Narrabri Shire have been estimated to include the creation of a further 450 jobs created in the wider economy.

The Narrabri Shire Council (2020, p. 60) intends to support the N2IP through a series of measures, including:

- Prepare a masterplan to guide the development of the N2IP
- Amend Narrabri's Local Environmental Plan to facilitate the delivery of the N2IP precinct
- Support the construction of the rail spur to the N2IP precinct
- Provide new serviced land for freight and logistics and related activities within the N2IP precinct
- Protect the N2IP precinct and key freight routes from sensitive land uses that may affect the efficiency and operation of the precinct and moving products to market.

A map of the N2IP precinct is provided in Figure 3 below.

Figure 3: Northern NSW Inland Port Precinct Location



Source: Narrabri Shire Council (2020, p. 68).

Several manufacturing development projects have been tentatively announced in the event the NGP goes ahead that would also probably participate in the N2IP.

In late February 2019, Santos (2019a) announced that it had entered into a non-binding agreement with Perdaman for the supply of 14.5 PJ of natural gas per annum over 20 years, subject to a final investment decision for the NGP.

In May 2019 Santos (2019c) announced that it had signed a non-binding memoranda of understanding with Brickworks for the supply of natural gas from the NGP. Under the proposed transactions, Santos would supply Brickworks with up to 3 PJ per year of natural gas from Narrabri for seven years from 2025. The supply of Narrabri gas is subject to a final investment decision, negotiation and execution of a definitive gas supply agreement and approvals by each party.

In July 2020 Santos (2020b) signed a Memorandum of Understanding with Natural Soda to use salt removed from produced water as part of the NGP. Santos and Natural Soda committed to undertaking a concept study to produce sodium bicarbonate in Narrabri. Sodium bicarbonate, more commonly known as 'baking soda', is not manufactured in Australia and is imported for use in food, pharmaceuticals and a wide range of industrial uses.

3. Eastern Gas Region

3.1 Overview

The Eastern Gas Region is an interconnected gas grid connecting all of Australia's eastern and southern states and the Australian Capital Territory (ACT) (Australian Energy Market Commission, 2019).[5]

Gas production in the Eastern Gas Region began around 50 years ago (Australian Energy Regulator, 2018, p. 180). Relatively low prices at that time encouraged residential, commercial and industrial

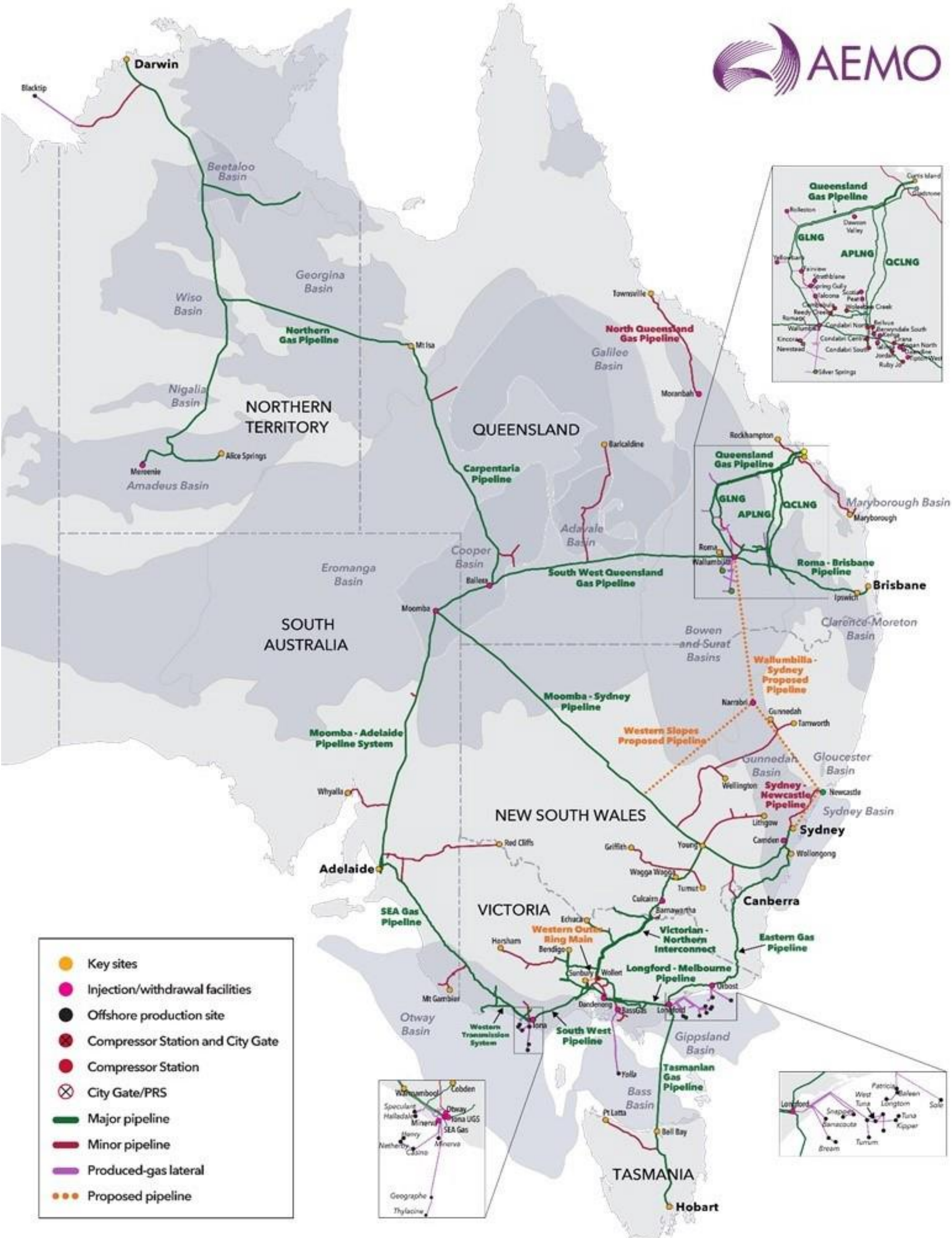
[5] For the purposes of this report the term Eastern Gas Region has been adopted as used by the Australian Energy Market Commission. The same region has also been described as the east coast gas market (Australian Competition and Consumer Commission, 2016, p. 1) and the south-eastern Australian gas markets (Australian Energy Market Operator, 2020a, p. 13).

customers to use gas. Gas use later expanded into the electricity generation market, because the comparatively rapid responsiveness of gas-powered turbines make them suitable for peak electricity generation capacity and combined cycle intermediate load generation. Gas-powered generators (GPG) also play an important role in managing fluctuations in intermittent wind and solar generation. More recently, gas has become a major export industry in the Eastern Gas Region, with the launch in early 2015 of the three liquid natural gas (LNG) export projects at Curtis Island in Queensland.

The Eastern Gas Region has evolved from separate state-based markets, each served by a single gas basin and a single transmission pipeline (Australian Energy Regulator, 2018, p. 182). Over the past 20 years, new pipeline investment has interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. This interconnected network further expanded with the opening in December 2018 of the 622 kilometre (km) Northern Gas Pipeline linking Tennant Creek in the Northern Territory with Mount Isa in Queensland. For the first time, the new pipeline allows the Eastern Gas Region to source gas from the Bonaparte Basin in the Timor Sea (located between the Northern Territory and East Timor).

NSW, Victoria, Queensland, SA, Tasmania and the ACT are now connected through a series of gas transmission pipelines that make up the Eastern Gas Region. This is outlined in Figure 4 below.

Figure 4: Map of Basins, Major Pipelines and Load Centres for Eastern Gas Region



Source: Australian Energy Market Operator (2022a, p. 50).
Note: Aside from the Western Outer Ring Main, all other proposed pipelines are potential future projects only.

Traditionally, the Eastern Gas Region operated in isolation from other gas markets in Australia and overseas because there were no gas exports from or imports to the region (Jacobs SKM, 2014, p. 4). In turn, the Eastern Gas Region had a balanced gas market in which the production of conventional gas largely from the Gippsland Basin in offshore Victoria and the Cooper Basin located in the southwest part of Queensland and northeastern South Australia had been more than sufficient to meet demand (Wood, 2015, p. 2).

Starting in the late 1990's, CSG from Queensland began to enter the Eastern Gas Region (Forcey & McConnell, 2017, p. 10). The onshore Cooper Basin and the offshore Gippsland Basin dominated gas production until 2002, when Cooper Basin production began to decline (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 13). In its place, CSG production dramatically increased in the Surat and Bowen Basins in Queensland from 2006.

By 2007, estimated CSG resources had outgrown the requirements of the domestic market and CSG developers sought monetisation of the resource in new, larger markets, the most accessible of which were Asian LNG markets (Jacobs SKM, 2014, p. 11). Several export projects were proposed between 2007 and 2008 and three projects commenced construction in 2011 and 2012 (Jacobs SKM, 2014, p. 12).

Located in the Eastern Gas Region at Curtis Island near Gladstone in Queensland are three LNG export projects each operating two trains:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa)
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa (Australian Energy Regulator, 2022a, p. 131).

Train 1 of the QCLNG is jointly owned by multinational energy company Shell (QGC) with a 50% interest and the Chinese National Offshore Oil Corporation (CNOOC) with a 50% interest while train 2 is majority owned by Shell with a 97.5% interest and with a small 2.5% interest owned by Tokyo Gas.

GLNG is a joint venture developed and led by Santos (2015a) with a 30% interest, in partnership with Malaysian national oil and gas company PETRONAS with a 27.5% interest, French energy company Total with a 27.5%interest, and the Korea Gas Corporation (KOGAS) from South Korea with a 15% interest.

APLNG is a joint venture operated by US oil and gas company ConocoPhillips with a 47.5% interest, Australian energy company Origin Energy with the 27.5% interest, and China Petrochemical Corporation (Sinopec) with a 25% interest.

The three Queensland LNG export projects are understood to be underwritten by long-term contracts of 20 years or more that commenced once each train became commercial, with LNG prices linked to crude oil prices coupled with take-or-pay provisions. According to Origin Energy (2018, p. 36):

> *The vast majority of APLNG gas reserves are sold under 20 year take or pay contracts to major Asian counterparties on an oil-linked basis …*

Take-or-pay provisions allow the buyer to unilaterally decide to take less than the contracted volume in return for compensating the seller for the supply that was not taken (Hartley, 2014, p. 7).

It has been estimated that long-term contracts account for around 76% of the total production capacity of the Queensland LNG export projects on a long-term basis (McKinsey & Company, 2017, p. 11).

3.2 Gas Production

The main production basins within the Eastern Gas Region are the Surat and Bowen Basins in Queensland, the Cooper Basin in SA and Queensland and three basins off coastal Victoria, the largest of which is the Gippsland Basin. This is outlined in Table 2 below.

Table 2: Gas Basins Serving the Eastern Gas Region in 2021

	Gas Production 12 months to December 2021	
Gas Basins	Petajoules (PJ)	Share of Eastern Australia Supply (%)
Surat–Bowen (Qld)	1,532	76%
Cooper (SA–Qld)	91	5%
Gippsland (Vic)	290	14%
Otway (Vic)	35	2%
Bass (Vic)	7	0.3%
Sydney and Gunnedah (NSW)	3	0.2%
Amadeus (NT)	15	1%
Bonaparte (NT)	44	2%
Eastern Gas Region Total	**2,018**	
Domestic Gas Sales	**586**	
LNG Exports	**1,432**	

Sources: EnergyQuest, *Energy Quarterly, March 2022* as cited by the Australian Energy Regulator (2022a).

While most of the Eastern Gas Region's gas reserves are located in the Surat and Bowen Basins in Queensland, those reserves are now largely committed to the LNG export industry (Australian Energy Regulator, 2018, p. 201). The South West Queensland Pipeline (SWQP) that runs from Wallumbilla to Moomba, acts as a gateway between the large northern gas fields (including the LNG export terminal at Gladstone) and southern regions where much of the highly seasonal demand is located (Australian Energy Market Operator, 2021, p. 48).

Historically, there have been strong levels of production from the Victorian gas basins – Gippsland, Otway, and Bass (Australian Energy Market Operator, 2019, p. 35). Production in the Gippsland Basin is dominated by the Gippsland Basin Joint Venture (GBJV) composed of Esso (a subsidiary of energy company ExxonMobil) and Woodside Energy (formerly BHP). However, several of the Gippsland fields are projected to reach their end of life between mid-2023 and mid-2024, and all currently producing fields in the Otway Basin will cease production unless anticipated gas field development or plant modification projects proceed (Australian Energy Market Operator, 2020, p. 8).

The Cooper Basin has been an important source of supply for the South Australian market via the Moomba to Adelaide Pipeline System (MAPs), and for the NSW market via the Moomba to Sydney Pipeline (MSP) (Australian Competition and Consumer Commission, 2016, p. 29). The Cooper Basin is a mature conventional gas production area, having been in production for around 50 years (Oakley Greenwood, 2017, p. 40). The Cooper Basin's peak gas production occurred around 2000-2002 after which it entered a tail gas phase where new deliverability projects are unable to arrest the natural decline in production due to a reduction in available 2P gas reserves (Oakley Greenwood, 2017, p. 41).

Santos is the major producer in the Cooper Basin, leading the South Australian Cooper Basin joint ventures and the South West Queensland Cooper Basin joint ventures. The Santos-led joint ventures, alongside Beach Petroleum as the other major participant, control most of the gas reserves in the Cooper Basin (Australian Energy Regulator, 2018, p. 188).

The bulk of production from the Cooper Basin has now been committed to the GLNG project (Australian Competition and Consumer Commission, 2017, p. 29). Santos entered an agreement in

2010 to supply GLNG with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional gas reserves (Australian Energy Regulator, 2018, p. 188).

NSW has only been a small producer of gas and has been reliant on importing gas from Queensland or South Australian Cooper Basin producers through Moomba via the MSP or from Victoria through the Eastern Gas Pipeline (EGP) (Oakley Greenwood, 2017, p. 33). Historically, around 40% of NSW's gas has come from the Cooper Basin, around 55% has come from Victoria and around 5% has come from NSW (GHD, 2017, p. 3.2).

The most significant production of natural gas in NSW has come from the Camden Gas Project operated by AGL. The Camden Gas Project has been in operation since 2001 and supplies around 5% of NSW demand (AGL Energy Limited, 2019). The Project produces CSG throughout the Macarthur region of NSW. The field is located around 65 km south-west of Sydney and operates within the Camden, Campbelltown and Wollondilly local government areas. In February 2016, AGL announced that it will progressively decommission wells and rehabilitate sites at the Camden Gas Project prior to ceasing production in 2023.

Small amounts of CSG are currently being produced in the Gunnedah Basin from the Narrabri Gas Project (NGP) exploration wells to supply gas to the Wilga Park Power Station (General Purpose Standing Committee No. 5., 2012, p. 11).

With the opening of the Northern Gas Pipeline in January 2019, the Northern Territory's offshore Bonaparte Basin and onshore Amadeus Basin became new suppliers to the Eastern Gas Region (Australian Energy Regulator, 2021, p. 187).

3.3 Gas Consumption

Demand for gas in the Eastern Gas Region has evolved in recent years, from mainly serving domestic consumers, to now servicing a growing LNG export market (Australian Energy Market Operator, 2019, p. 17). Consumption of natural gas from the LNG export projects now dwarfs that of domestic users (Bethune & Wilkinson, 2019, p. 520). In 2021 LNG exports accounted for around 71.8% of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2022a).

Gas is used in different ways across the Eastern Gas Region. In Victoria, gas consumption is dominated by the residential/commercial sector with heating representing a significant proportion of usage, but in Queensland, this sector has a very small proportion of regional gas consumption, with markedly less gas used for heating (Australian Energy Market Operator, 2019, p. 19). Gas consumption in Queensland is dominated by the LNG export sector.

Table 3 below provides the estimated gas consumption by region and purpose within the Eastern Gas Region during 2021.

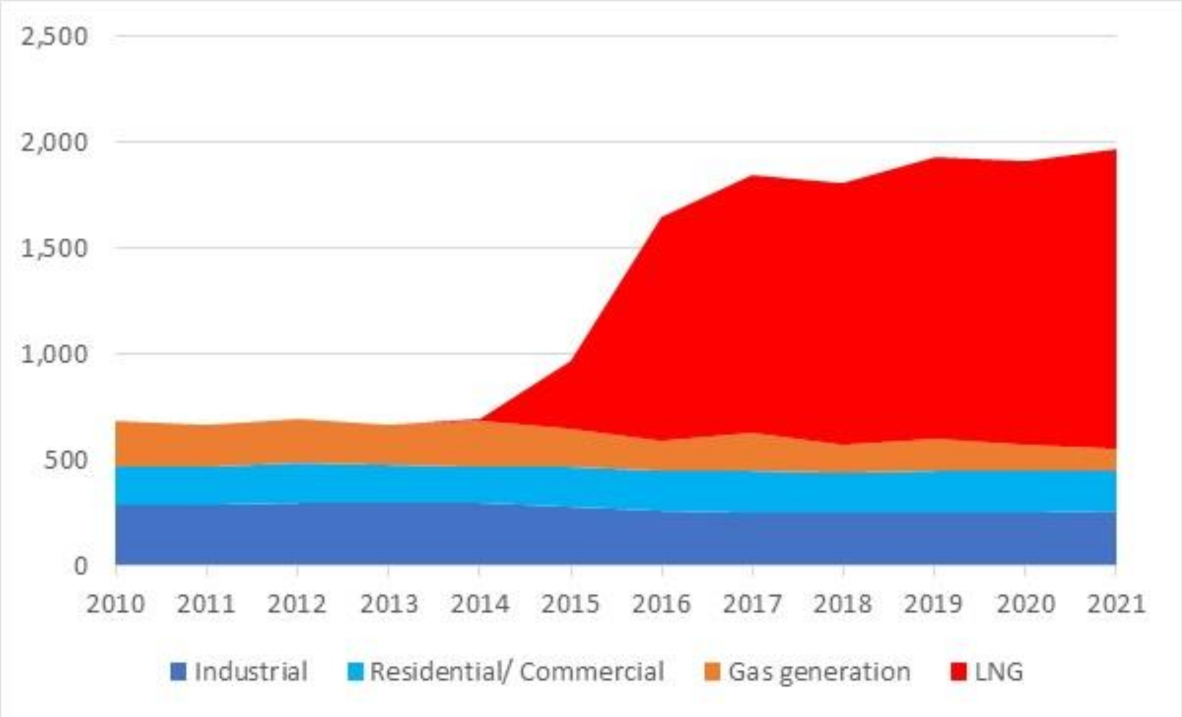
Table 3: Estimated Regional Consumption of Gas within the Eastern Gas Region by Sector - 2021

Region	Residential/ Commercial (%)	Industrial (%)	Gas-Powered Electricity Generation (%)	LNG Exports (%)	Regional Gas Consumption (PJ)
Queensland	0.4%	7.0%	2.3%	90.3%	1,558.5 PJ
New South Wales	44.3%	47.7%	8.0%	0%	113.7 PJ
South Australia	14.2%	31.3%	54.5%	0%	76.6 PJ
Tasmania	11.4%	85.5%	3.2%	0%	7.1 PJ
Victoria	62.8%	32.1%	5.2%	0%	204.5 PJ
Total	10.0%	13.2%	5.0%	71.8%	1,960.4 PJ

Source: Australian Energy Market Operator (2022a).

Actual consumption of natural gas by sector is provided below in Figure 5 below which outlines the significant ratcheting up of gas consumption by the LNG export projects since 2014.

Figure 5: Eastern Gas Region Natural Gas Consumption by Sector – 2010 to 2021 (PJ)



Source: Australian Energy Market Operator (2022a).

For 2023, the ACCC (2022a, p. 7) is forecasting that 1299 PJ of gas will be exported under long term contracts with overseas buyers. The remaining gas the LNG exporters are expected to produce, above their contractually committed volumes, can be supplied either to the domestic market or to overseas markets. However, since 2018, the LNG exporters have exported at least half - and more frequently, around 70% - of their excess gas to overseas spot markets.

3.4 Gas Trading

The majority of gas in the Eastern Gas Region is traded through bilateral contracts (Australian Energy Regulator, 2022a, p. 121). The two main levels of gas contracts (also known as gas supply agreements or GSAs) are:

- offers by gas producers to very large customers such as major energy retailers and gas-powered generators (GPG)
- offers by retailers and aggregators that buy gas from producers and on sell it to commercial and industrial (C&I) customers.

Aside from GSAs, wholesale gas within the Eastern Gas Region can also now be traded on a short-term basis through the Victorian declared wholesale gas market (DWGM), the Short Term Trading Market (STTM) operating in Sydney, Adelaide and Brisbane, and the Wallumbilla Gas Supply Hub (GSH) west of Brisbane and the Moomba GSH. Spot markets allow wholesale customers to trade gas without entering long-term contracts (Australian Energy Market Operator, 2022a, p. 121).

The Eastern Gas Region was historically characterised by long-term GSAs where wholesale gas buyers typically had few difficulties renegotiating their GSAs when they expired (Australian Competition and Consumer Commission, 2016, p. 29). Gas supplied to industrial users under long-term GSAs was historically priced using a cost-plus formula, in which the contract price paid for gas by users was calculated based on the cost of production plus a margin and escalated with inflation. Non-price terms such as the duration of GSAs, price review mechanisms, quantities (including flexibility on delivered quantities) and delivery locations were typically rolled over from one GSA to another and remained relatively stable.

From the late 1970s until 2010, domestic gas production in the Eastern Gas Region had taken place in an environment of relatively low gas prices (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 13). Until approximately 2010, new gas contracts were available in eastern Australia at price levels that had remained steady in real terms over the previous decade or longer (Jacobs SKM, 2014, p. 11). Domestic gas contract prices historically averaged around $3-$4 per GJ (Australian Energy Regulator, 2018, p. 208).

The development of the three LNG export projects precipitated uncertainty about the future supply-demand balance within the Eastern Gas Region (Australian Competition and Consumer Commission, 2016, p. 24). According to the ACCC (2016, p. 24), this uncertainty was exacerbated by the Santos-led GLNG purchasing substantial volumes of gas in the domestic market to supplement production from its inadequate reserves, with a large portion of this gas coming from the Santos dominated Cooper Basin that historically had supplied NSW and South Australia. In turn, wholesale gas prices offered to domestic users began to rise.

Where gas contracts had traditionally locked in prices and other terms and conditions for several years (Australian Energy Regulator, 2018, p. 208), the industry has more recently shifted towards shorter term contracts with review provisions. Coinciding with the growing uncertainty regarding future gas availability, many long-term domestic GSAs were set to expire over the course of 2016 through to 2018 (Australian Competition and Consumer Commission, 2016, p. 24). Anticipating potential gas supply challenges, several industrial gas users approached gas suppliers in the period from about 2012 to the end of 2014 to secure gas for supply in 2016 and beyond. Many quickly found that they had fewer options for gas supply than previously, and some users encountered difficulties getting any offers at all for supply in certain periods. Where offers were made, they were often at substantially higher prices and on less flexible terms than in the past.

Jacobs SKM (2014, p. iii) reported in April 2014 in relation to new GSAs that:

- Prices have escalated since before 2010 and cover a wide range from approximately $5.50/GJ to $10.00/GJ
- Prices in Queensland appear to have escalated further in 2013 relative to 2010-2012 as more third-party gas has been purchased by the LNG exporters
- Prices for gas in southern states, sourced from the Gippsland Basin Joint Venture (GBJV), are lower than those in Queensland but may be set to escalate to parity levels.

With the commencement of LNG exports in early 2015, the Eastern Gas Region was transformed from a captive domestic “buyer's” market to an internationally-linked “seller's” market (Forcey & McConnell, 2017, p. 12). In turn, the development of the three LNG export projects in Queensland exposed domestic gas users to international gas prices for the first time (Australian Competition and Consumer Commission, 2016, p. 22).

The ACCC (2016, p. 45) has suggested that future domestic gas prices in Queensland will typically be influenced by LNG netback prices, which represent the maximum amounts the LNG projects would be willing to pay to purchase third party gas. LNG netback prices represent the export parity price a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically (Australian Energy Regulator, 2018, p. 210). It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or ‘netting back’ the costs of converting gas to LNG and shipping it overseas. The cost includes liquefaction, shipping to Asia and regasification in Asia. If LNG netback prices exceed domestic prices, it becomes more profitable to export gas than to sell it locally.

GSAs signed around 2015 were often for around $6 per GJ; in late 2016 prices offered to industrial customers began to rise rapidly, peaking above $20 per GJ in the first half of 2017 (The Australian

Industry Group, 2018, p. 9). Domestic price offers in the first half of 2017 were significantly above LNG netback prices, peaking at offers as high as $22 per GJ in March 2017 (Australian Competition and Consumer Commission, 2018a, p. 12).

Gas price offers then fell to around $8–12 per GJ between July and November 2017 (Australian Competition and Consumer Commission, 2018, p. 9). The range of gas price offers narrowed further over subsequent months, with most offers between November 2017 and January 2018 being made between $8–10 pert GJ.

Most offers made in the first quarter of 2018 for gas supply in 2019 were priced in the high-$8 to $11 per GJ range (Australian Competition and Consumer Commission, 2018a, p. 39). By the end of the first quarter of 2018, prices offered in the domestic market for gas supply in 2019 had converged with expected LNG netback prices at Wallumbilla for 2019.

Over the course of 2018, however, offered prices trended upwards (Australian Competition and Consumer Commission, 2019, pp. 10-11). In the period between June and November 2018, most offers were above $10 per GJ with a number of offers above $12 per GJ (Australian Competition and Consumer Commission, 2019, p. 11).

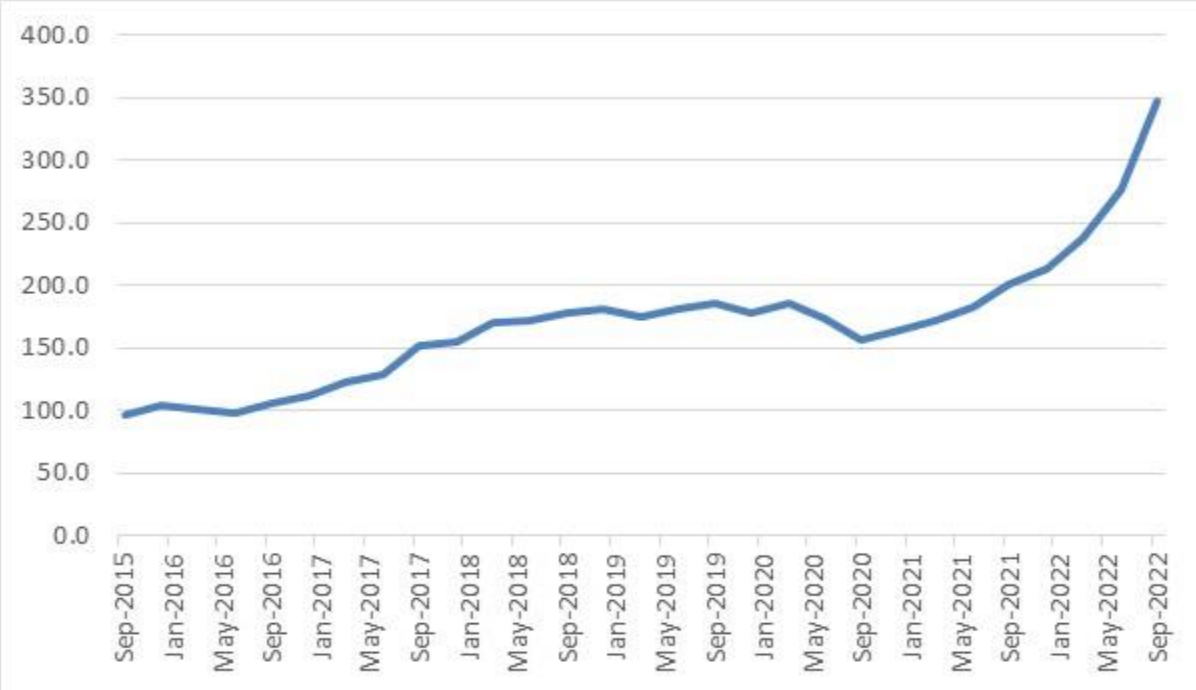
Prices offered for 2021 supply by both producers and retailers GSAs declined noticeably from $8–14 per GJ over the second half of 2019 to $6–8 per GJ by mid-2020 (Australian Competition and Consumer Commission, 2021, p. 7). Prices remained stable over the second half of 2020, with most offers falling between $6-8/GJ (Australian Competition and Consumer Commission, 2021a). Prices offered for 2022 supply increased from $6-8 per GJ in late 2020 to around $7-$9.50 by mid-2021 (Australian Competition and Consumer Commission, 2022, p. 14).

Prices offered for supply in 2023 increased over the course of 2021, accelerating from around August 2021 (Australian Competition and Consumer Commission, 2022a, p. 11). Prices offered around $16 per GJ, made between November and December 2021, were the highest observed since early 2017. There were also reports of even higher prices being offered to commercial and industrial users in April and May 2022, with gas price offers as high as $21.20 per GJ (Australian Competition and Consumer Commission, 2022a, p. 12).

During October 2022 there were conflicting reports on just how expensive contracted gas was becoming, with producers saying gas was available in the teens per GJ range while one manufacturing source said they had been offered a 12-month contract at $30 per GJ (Macdonald-Smith & Fowler, 2022). Gordon Martin, an executive director of Coogee Chemicals, has said the best offer they could get was under $24 per GJ for two years, compared to just under $48 per GJ on its last contract for its Brisbane plant.

Since 2015-16, gas prices have more than tripled in the Eastern Gas Region, which is outlined in Figure 6 below.

Figure 6: Index Numbers of Gas Prices in the Eastern Gas Region – September 2015 to September 2022



Source: Australian Bureau of Statistics (2022).

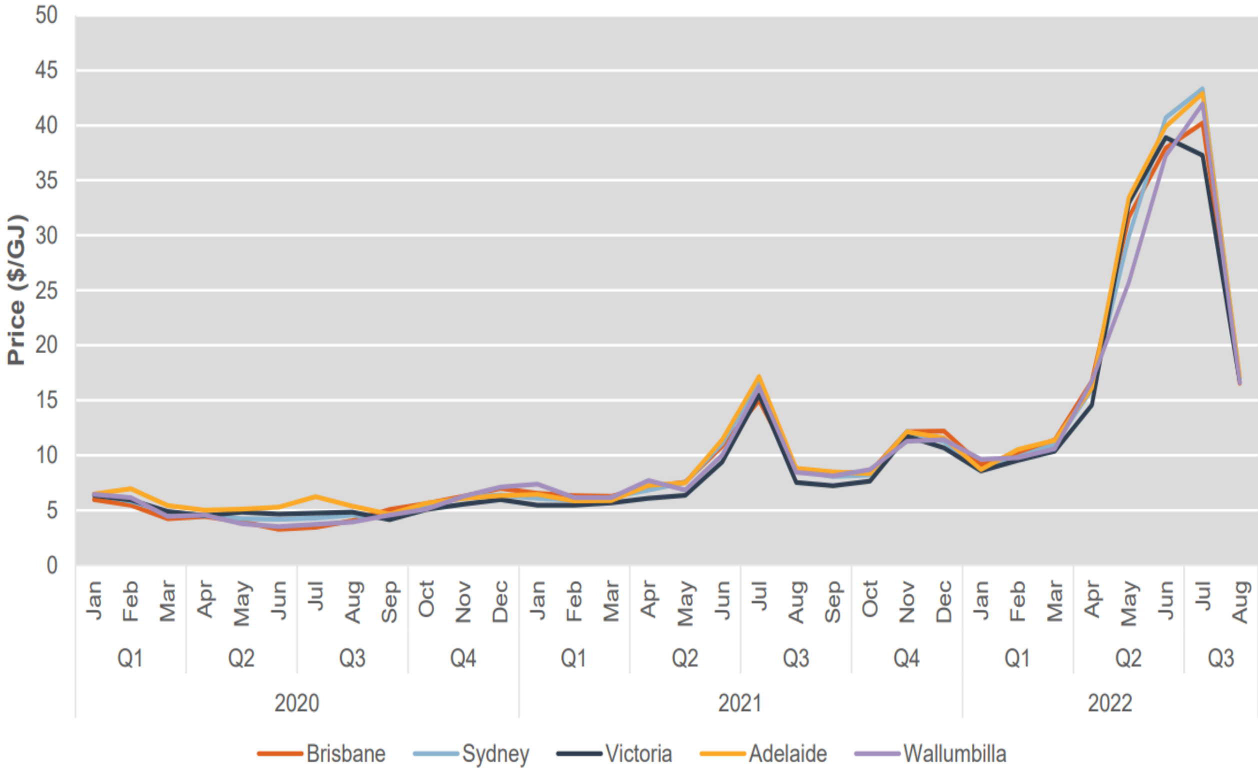
3.5 Recent Gas Price Turmoil

Wholesale gas spot prices within the Eastern Gas Region have dramatically increased since late March 2022 with increased demand triggered by the need for more GPG. This coincided with a series of unplanned coal power generator outages across the eastern states, as well as coal supply constraints in NSW (Macdonald-Smith & Greber, 2022).

In late May 2022 the AEMO (Australian Energy Market Operator, 2022) imposed administered price caps ($40 per GJ) in the Sydney and Brisbane short term trading markets and imposed administered price caps on Victoria's gas market at the end of May. This came following the failure of NSW gas retailer Weston Energy in late May that resulted in hundreds of customers being transferred to other retailers and put on tariffs based on spot prices (Macdonald-Smith, 2022c).

Recent increases and falls in wholesale gas spot prices in the Eastern Gas Region are outlined in Figure 7 below. Spot prices exceeded $40 per GJ during the winter of 2022 but have since fallen.

Figure 7: Wholesale Gas Spot Prices in the Eastern Gas Region – January 2019 to July 2022 ($ per GJ)



Source: Australian Energy Regulator (2022, p. 5).

Although not connected to recent gas price rises in the Eastern Gas Region, international gas prices, including Asian LNG import prices, have increased with rising geopolitical tensions since the beginning of the year with the Russian invasion of the Ukraine commencing in late February. Global LNG prices remain elevated and highly volatile as the fallout from Russia's invasion of Ukraine continues (Department of Industry, Science and Resources, 2022a, p. 76). Fears of a gas shortage in Europe have sent buyers scrambling for the world's remaining uncontracted LNG cargoes. Amidst the rush, Asian customers now face the prospect of competing with European importers.

4. Gas Supply Issues

4.1 Do Gas Producers Exercise Market Power?

Concerns regarding the exercise of market power by gas producers in the Eastern Gas Region are not new. As the Productivity Commission (2015, p. 23) has previously observed:

> *Some gas market stakeholders have argued that gas producers in the eastern Australian gas market have market power, and that the exercise of this power is affecting market outcomes, including the ability to secure a contract on competitive terms for gas purchases. A number of large industrial gas users have indicated that they are unable to secure contracts at any price (or that there is a risk of this happening). Some users have suggested that this too is a manifestation of the exercise of market power.*

The economic and legal literature has provided several different definitions of market power. One commonly used definition in economics is that provided by US economist Abe Lerner which is the ability of a firm to push its price above marginal cost (Lerner, 1934). However, the problem with the

Lerner definition of market power is that it is often difficult to measure marginal cost in the real world.

Another definition of market power comes from prominent US competition law scholars Carl Kaysen and Donald Turner (1959, p. 75):

> *A firm possesses market power when it can behave persistently in a manner different from the behaviour that a competitive market would enforce on a firm facing otherwise similar cost and demand conditions.*

This definition has been used by the ACCC (2002, p. 64) and in a prominent Australian legal judgement.[6]

Identifying firms that have substantial market power enables one to distinguish between conduct that might harm consumers and conduct that cannot (Bork & Sidak, 2013, p. 511). Unfortunately, there is no definitive test for the exercise of market power. Instead, one must rely on a series of partial indicators in order to determine whether firms participating in a market are exercising market power. According to US competition law scholar Judge Robert Bork and Professor Gregory Sidak of Tilburg University (2013, p. 512):

> *Courts and competition authorities around the globe typically rely on indirect evidence of market power, such as market share and barriers to entry.*

Information on market share can be a useful first step in competition analysis and can provide guidance as to whether a given case is more likely to raise oligopoly issues or single firm conduct issues (Organisation for Economic Co-operation and Development, 2006, p. 8). An oligopoly is a market structure characterised by a few participants. It may include a "competitive fringe" of numerous smaller sellers who behave competitively because each is too small individually to affect prices or output (Areeda, Solow, & Hovenkamp, 2002, p. 9).

There is no single determinate solution to the problem of oligopoly with many possible outcomes being postulated. The range of solutions runs the full gamut of possible outcomes from that reminiscent of perfect competition to that of a monopoly (Areeda, Solow, & Hovenkamp, 2002, p. 10). The reason that there is no single unique solution to the problem posed by oligopoly is because of the interdependency of market participants. For an individual oligopolist the quantity of product which it is capable of selling at any given price is dependent on the price charged by its competitors, which in turn is affected by the price set by the individual oligopolist in the first instance (Fellner, 1949, p. 11).

Several theories of oligopoly predict that once firms recognise their interdependency, their most rational course of action would be to behave in a manner reminiscent of a monopoly. The outcome from these models has been described as tacit collusion, also known as conscious parallelism. Even where oligopolistic firms may not be part of a formal cartel arrangement that are seeking to collude by cutting back on production and raising prices, they may still be able to coordinate their conduct so that an outcome similar to a cartel or monopoly is achieved.[7]

[6] Cited with approval by Dawson J in *Queensland Wire Industries Proprietary Limited v The Broken Hill Proprietary Company Ltd and Anor* (1989) 167 CLR 177 at 200.

[7] A cartel is where there is a formal agreement amongst competing firms to collude to fix prices or cutback on production. The objective of a cartel is to organise firms so they behave in manner similar to the outcome achieved by a monopoly. Within market economies, there are generally competition laws (also known as antitrust laws) prohibiting cartel arrangements.

The available evidence suggests the production of gas in the Eastern Gas Region is best characterised as an oligopoly with a competitive fringe based on current gas production as well as holdings of 2P reserves and 2C resources.

Any competitive tensions in the supply of gas for the Eastern Gas Region that may have previously existed evaporated when Santos decided to prioritise and redirect the bulk of its Cooper Basin gas production to GLNG and the LNG export market. According to the ACCC (2016, p. 42):

> *… there has been a significant change in the pricing dynamics in the southern states as a result of the decisions made by the Cooper Basin producers, particularly Santos, to commit significant volumes of gas produced in the Cooper Basin to the LNG projects. The Cooper Basin producers historically played a critical role in competing with the GBJV for market share in the southern states. The reduction in the diversity of gas suppliers in the southern states has substantially strengthened the competitive position of the GBJV and has severely undermined the bargaining position of domestic users in negotiation with the GBJV.*

With the commencement of the three LNG export projects, gas producers in the Eastern Gas Region now have an export option for their gas while any of the LNG projects require additional gas to meet their contractual export commitments or fill spare production capacity in their trains (Australian Competition and Consumer Commission, 2016, p. 45). This means that domestic gas users in Queensland will have to directly compete with the LNG projects for any gas that is available for supply in Queensland. Similarly, domestic gas producers are likely to be seeking a price that is commensurate with an amount the LNG projects are willing to pay.

On an aggregate basis, the LNG exporters and their associates were responsible for 77% of gas production in the Eastern Gas Region during 2020-21 (Australian Competition and Consumer Commission, 2022a). The LNG exporters and their associates also had influence over close to 90% of the 2P reserves in the east coast in 2021, through a combination of their direct interests in 2P reserves, joint venture and exclusivity arrangements (Australian Competition and Consumer Commission, 2022a, p. 6). In turn, the ACCC (2022a, p. 15) has reflected:

> *This highlights the effective control that the LNG exporters have over the supply and development of gas in the east coast, as well as competition in the domestic market.*

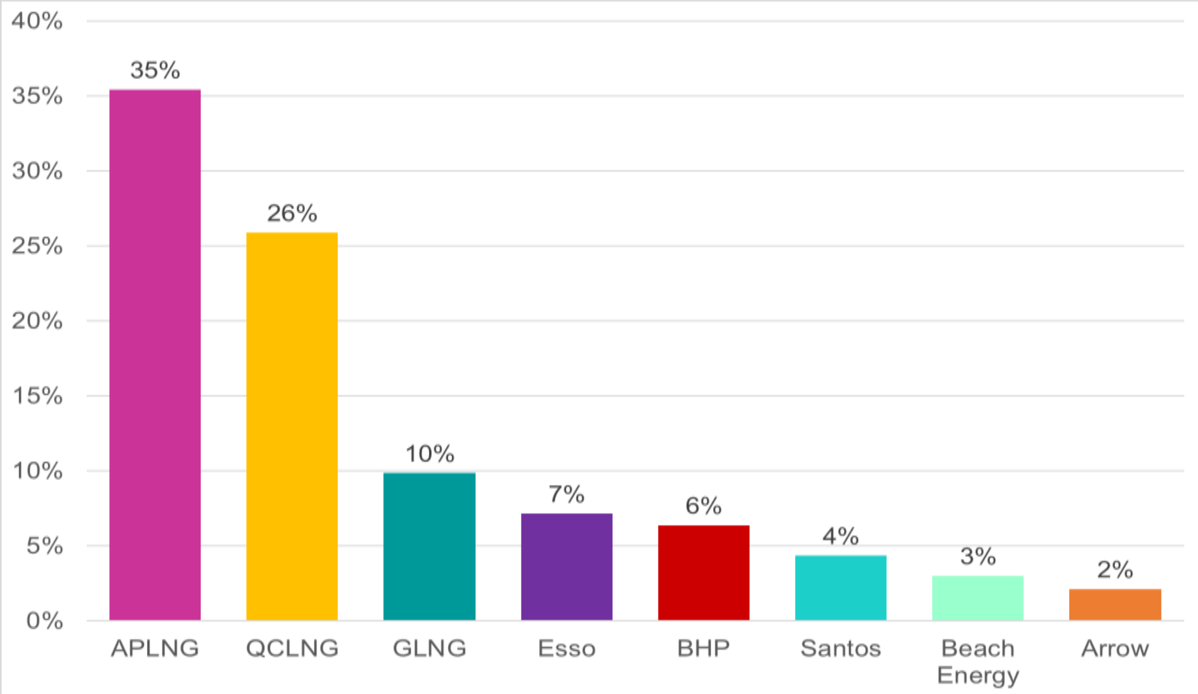
Further, the LNG exporters and their associated control 83% of 2C resources in the Eastern Gas Region (Australian Competition and Consumer Commission, 2022a, p. 99).

Due to the stranglehold the LNG exporters exercise over the supply of gas in the Eastern Gas Region, the ACCC (2022a, p. 6) has warned:

> *This may increase the risk of coordinated conduct and increase the market power of the LNG exporters.*

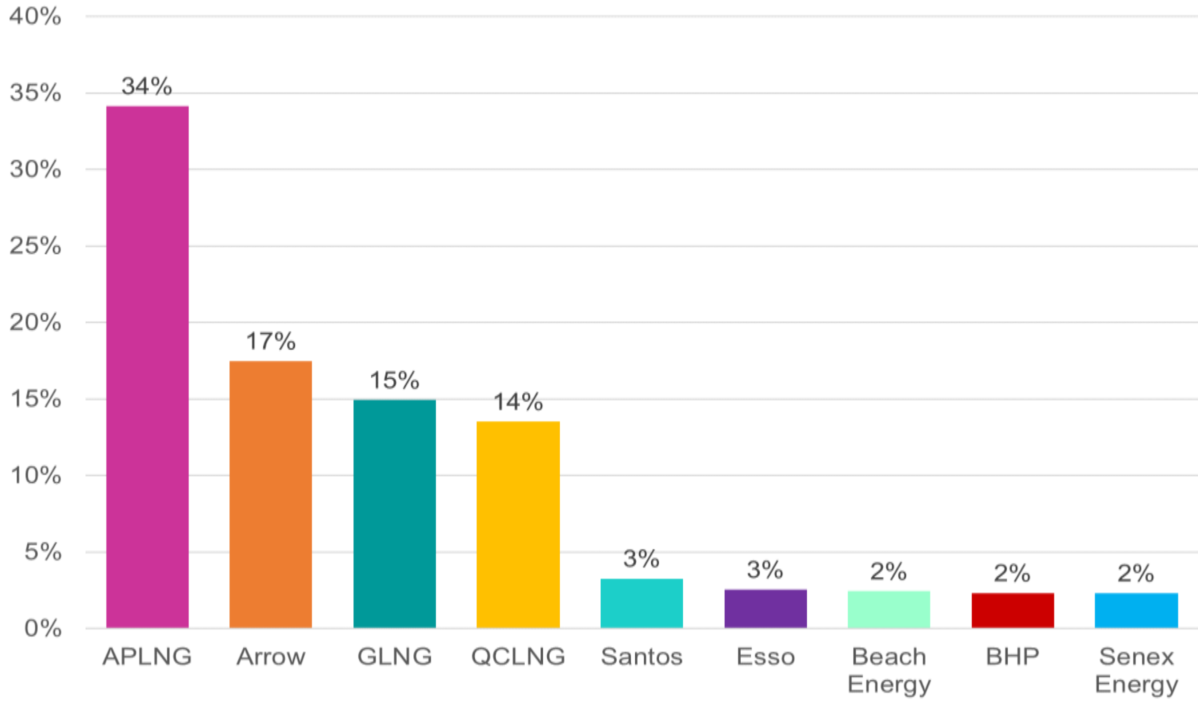
Details on production, 2P reserves and 2C resources held in the Eastern Gas Region is provided in Figures 8, 9 and 10 below.

Figure 8: Production by Gas Producers in the Eastern Gas Region in 2020-21



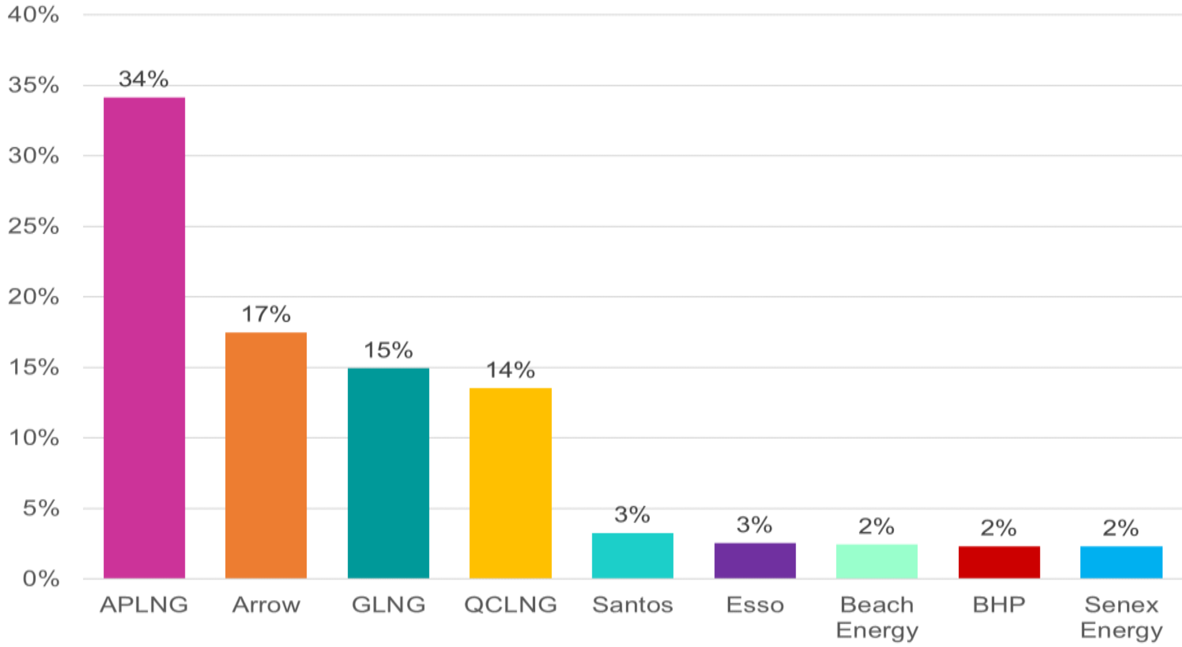
Source: ACCC (2022a, p. 99).

Figure 9: 2P Reserves held by Gas Producers in the Eastern Gas Region (at 30 June 2021)



Source: ACCC (2022a, p. 99).

Figure 10: 2C Gas Resources held by Gas Producers in the Eastern Gas Region (at 30 June 2021)



Source: ACCC (2022a, p. 99).

According to the UK Office of Fair Trading (2004, p. 11):

> *In general, market power is more likely to exist if an undertaking (or group of undertakings) has a persistently high market share.*[8]

However, just because a market is characterised as having an oligopoly structure does not necessarily mean that it will be prone to tacitly collusive behaviour. While market concentration can certainly provide guidance as to which markets are likely to raise competition concerns, it is certainly not a definitive determinate of anti-competitive behaviour.

Prominent industrial organisation economist Joseph Bain (1956) considered the force of potential competition as a regulator of price and output of comparable importance to that of actual competition and focused on the height of barriers to entry as the critical determinant of the price level. According to Bain, the extent of barriers to entry in an industry indicated the advantage that allowed existing sellers to raise their price over the competitive level without attracting new entry. Bain postulated that barriers to entry would have the greatest impact in oligopolistic markets where collective action would permit the deliberate elevation of prices to the extent allowed by barriers to entry.

According to the ACCC (2016, p. 61), barriers to entry into gas production are high:

> *… gas explorers and small new producers in particular face major challenges to achieve the scale necessary to enter the market for the wholesale supply of gas due to the cost and risks associated with gas production.*
>
> *Gas exploration and production have high capital costs, are high risk and have long project execution timeframes. Petroleum exploration and production permits, whether offshore or onshore, typically require work commitments such*

[8] An undertaking covers any natural or legal person engaged in economic activity, regardless of its legal status (Office of Fair Trading, 2004, p. 2n).

as seismic surveys and/or drilling wells. These investments tend to be sunk costs, where the investments have few alternative uses in the event that no gas is discovered. Exploration is also characterised as an activity with a low and uncertain probability of success.

A number of features of gas production could dispose major producers towards tacit collusion and the exercise of market power:

- Market concentration on the selling side (Posner, 2001, p. 69). It is easier to coordinate a smaller number of firms.
- Standard (homogeneous) product (Posner, 2001, p. 75). Following processing, natural gas could be considered as a homogeneous product, thus minimising the scope for product differentiation and non-price competition and thereby providing a clear basis upon which a tacitly collusive agreement could be struck, namely the price of natural gas.
- Unconcentrated buying side of the market (Posner, 2001, p. 75). The incentive to break ranks from tacit collusion is lessened when the number of customers per seller increases as the reward from doing so diminishes (Stigler, 1964).
- Price competition is more important than other forms of competition (Posner, 2001, p. 76). When cutting prices is the only way of winning business away from competitors, eliminating price competition will yield higher profits.
- It is more difficult to cartelise the market for a durable than a nondurable product (Posner, 2001, p. 76). In many durable-goods industries, used products are traded in decentralised secondary markets not directly controlled by the producer that provide a source of competition and a substitute for new products. On the other hand, nondurable goods, such as natural gas, provide no such opportunities.
- Similar cost structures and production processes (Posner, 2001, p. 77). The more alike the firms in a market are with respect to the structure of their costs and to their production methods, the easier it will be for them to engage in tacit collusion.

The prevailing market structure as well as the characteristics of natural gas lend support to the ACCC implication that the three Queensland LNG exporters are exercising market power. In turn, a level of tacit collusion may be underpinning current domestic pricing of the three Queensland LNG exporters.

Further adding to concerns the Queensland LNG exporters may be exercising market power, there are longstanding concerns that there has been hoarding of gas reserves. According to the Productivity Commission (2015, p. 55):

Some large industrial gas users have suggested that gas companies are hoarding reserves, rather than developing them for production.

The ACCC (2020, p. 40) has previously commented that a number of smaller gas producers have suggested that some LNG producers and their affiliates have made decisions to 'bank' or 'warehouse' gas by delaying the development of some fields in order to meet their own commercial priorities. According to the ACCC (2020, p. 40):

One small producer in Queensland, for example, stated that it is "being prevented from developing its current modest reserves and resources due to the adjacent permit holder… not progressing their existing government approved…projects, for apparently global strategic reasons". Another small producer stated that one of the main barriers to the commercial recovery of its 2C resources is that its joint

> *venture partner, which is a larger producer, is "not motivated to pursue a larger development".*

While noting there may be legitimate reasons for larger producers wanting to bank' or 'warehouse' gas, the ACCC (2020, p. 40) has nonetheless raised the possibility that larger producers may be seeking to write down the level of their reserves in order to withhold supply to maintain or raise prices. In turn, the ACCC (2020, p. 40) has expressed the following concern:

> *… the ACCC is concerned that larger producers and LNG producers in particular may have the ability to delay the development of much needed new sources of supply to suit their commercial priorities at the expense of the domestic market.*

Reflecting on the period from late 2019 until early 2020, the ACCC (2020a, p. 6) commented in August 2020 that:

> *Domestic prices in Queensland have now diverged from export parity LNG netback prices by more than $2/GJ.*
>
> *This pricing behaviour raises questions about the degree of competition that currently exists in the supply of gas in East Coast Gas Market, at both the producer and retailer levels.*
>
> *The fact that LNG producers collectively sold 18 LNG spot cargoes into international markets at prices substantially below domestic gas price offers during this time increases our concerns about the level of competition in the market.*

The ACCC (2020, p. 57) has previously highlighted the fact that one of the Queensland LNG exporters was intending to sell several spot LNG cargoes in late 2019 during 2020 for prices presumably lower than they could have received in the domestic market:

> *Understanding this price differential is particularly important in light of recent reports that APLNG is offering to sell an additional six to 12 LNG cargoes in 2020 through a short-term LNG strip contract. These cargoes would likely be sold at prices reflective of current market expectations for LNG spot prices over 2020, which as noted above, are below domestic price offers in Queensland.*

This is not rational behaviour of suppliers in competitive markets.

The ACCC (2021, p. 7) observed in February 2021 for period from early 2020 to mid-2021 that domestic offer and GSA prices remained above export parity prices, although to a lesser than previously reported. The ACCC (2021a, p. 108) later observed there had been some narrowing of the disparity between the LNG netback price and offers in the later part of 2020.

In January 2022, the ACCC (2022, p. 19) observed that many domestic offers from LNG exporters do not appear to have been internationally competitive. The ACCC (2022, p. 99) observed that from March to August 2021, the expected LNG netback price exceeded the price of the majority of offers for supply in Queensland during 2022, although the ACCC reflected some suppliers appear to have been influenced in their domestic pricing by the perceived threat of regulatory intervention at prices around $10 per GJ or above. Despite offer prices falling below the expected netback price, the ACCC (2022, p. 70) suggested that competition was posing little constraint on producers' pricing decisions.

More recently gas users have reported that LNG exporters were making price offers linked to the ACCC's export parity price series (the LNG netback price series) for the first time, but expressed concern that this had only occurred once LNG netback prices were high (Australian Competition and Consumer Commission, 2022a, p. 12).

According to the Australian Energy Regulator (2022b, p. 13), when domestic prices are higher than international prices, the LNG exporters should face greater incentives to sell into the domestic market and drive the domestic price down. However, the AER found that between April and June 2022 when Asian spot LNG netback prices were lower than wholesale gas spot prices in the Eastern Gas Region, it was not clear this occurred. Rather perversely, the AER found domestic gas production in the Eastern Gas Region was actually flowing north towards the LNG exporters for processing and export as LNG during May and June 2022. In this regard, former ACCC Chair Rod Sims (2022) has observed that it is not in the financial interests of the three LNG exporters to boost domestic supply.

In October 2022 the Commonwealth Minister for Industry and Science, the Hon. Ed Husic (2022), reflected on the behaviour of LNG exporters in the following terms:

> *Well, the biggest thing that the gas companies can do right now is recognise that their business model would make a locust swarm proud.*
>
> *Now, at the moment, all they're doing is sucking up an Australian resource and selling it at phenomenal prices overseas and doing so in such a way that is putting pressure on manufacturers and households in this country.*
>
> *That cannot continue.*
>
> *…*
>
> *We're committed to revitalising manufacturing, lowering gas prices - they can either do the right thing by the country or they can continue to be greedy. It's Team Australia or Team greed. The choice is up to the gas companies, and I know what choice they should be making.*

Arguably, the LNG exporters are abusing their market power and behaving as a *de facto* cartel, deliberately withholding and withdrawing gas from the Eastern Gas Region, thereby raising gas prices. In turn, this has implications for the demand and supply balance in the Eastern Gas Region.

4.2 Demand and Supply Balance

Numerous parties have been predicting gas supply shortfalls in the Eastern Gas Region in the foreseeable future. According to the Australian Competition and Consumer Commission (ACCC) (2020, pp. 1-2):

> *The long-term supply outlook for the East Coast Gas Market from 2021–2031 remains uncertain. The Southern States risk facing a shortfall in the medium-term unless:*
>
> *• more exploration and development occurs in the south to compensate for declining ex-Longford production*
>
> *• more investment occurs in north-south transportation infrastructure to enable greater volumes of gas from Queensland or the Northern Territory to flow south, and*
>
> *• one or more LNG import terminals are developed.*

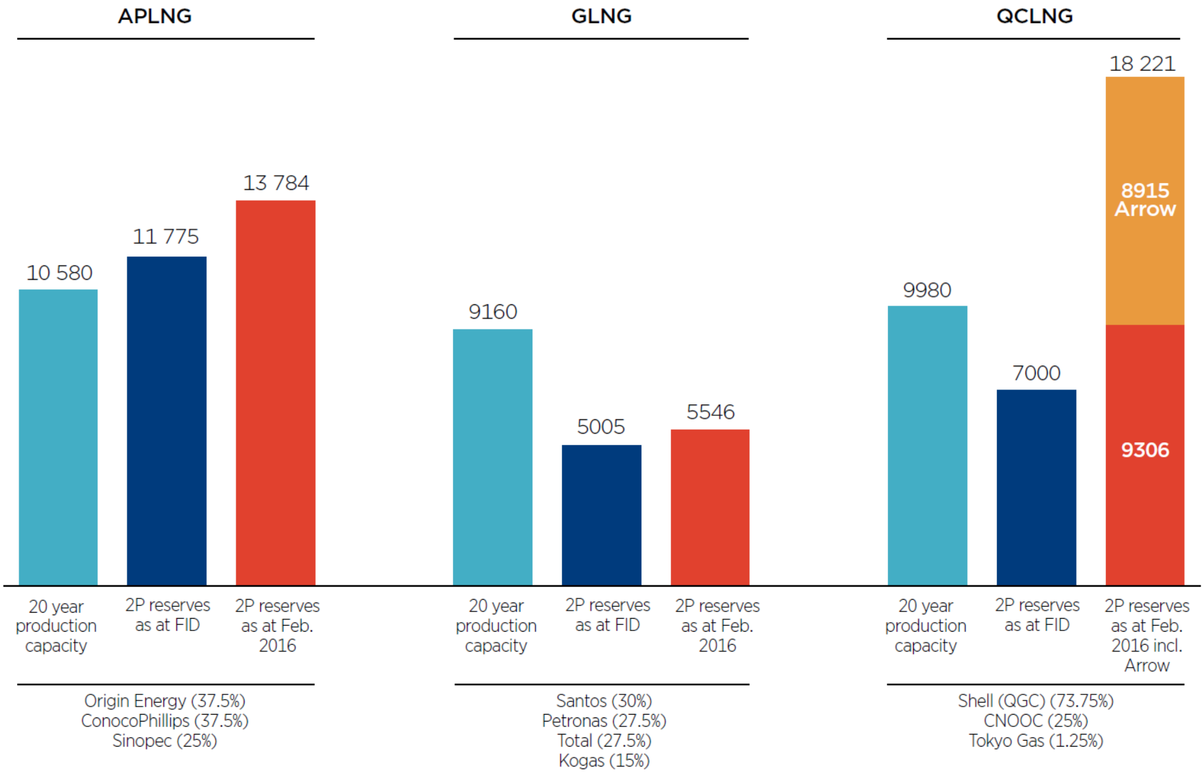
More recently, the AEMO (2022a, p. 4) in some scenarios forecasts a risk of gas shortfalls in extreme weather conditions from winter 2023. The risk arises in south-eastern regions where gas flow is constrained by existing pipeline capacity limits – New South Wales, the Australian Capital Territory, Victoria and Tasmania. After winter 2023, to 2026, the AEMO (2022a, p. 12) sees shortfall risks further reduced by some anticipated projects, although in the longer-term new sources of supply will be required even though annual domestic gas consumption is forecast to decline.

Similar to the AEMO, the ACCC (2022a, p. 7) has recently warned that if all the excess gas produced by LNG exporters is sold in overseas markets, then the domestic east coast gas market is likely to be 56 PJ short of gas needed to meet forecast demand for 2023. According to the ACCC (2022a, pp. 8-9), LNG exporters are expected to contribute to the shortfall in 2023 by withdrawing 58 PJ more gas from the domestic market than they expect to supply into the market. The ACCC (2022a, p. 9) arrived at this conclusion based as the LNG exporters expect to export the vast majority of their 167 PJ of 'excess gas'.

The supply of natural gas in the Eastern Gas Region has tightened since the Queensland LNG exporters started to draw on reserves (Australian Energy Regulator, 2017, p. 8).

Decisions made by one Queensland LNG exporter in particular, stand out as the root cause for any future impending natural gas shortfalls in the Eastern Gas Region. While APLNG and QCLNG primarily expected to meet their LNG export commitments through the development of gas resources owned by them, the Santos-led GLNG always expected to source gas from other producers in the Eastern Gas Region to supplement its CSG reserves (Australian Competition and Consumer Commission, 2016, p. 28). This is reflected in Figure 11 below which shows the total production capacity of the two GLNG trains significantly exceeded the volume of gas that GLNG could produce from its 2P CSG reserves at the time the project was sanctioned.

Figure 11: Expected LNG Plant Production Capacity and 2P Reserves of the Queensland LNG Projects (PJ)



Source: ACCC (2016, p. 28).

At the time the final investment decision was made to proceed with the GLNG project, it had only 5,005 PJ of 2P reserves (Santos Ltd, 2011, p. 10). However, Santos claimed that GLNG had ultimate 2P CSG reserves maturation of 9,848 PJ from existing acreage based on analysis by petroleum consultants Netherland, Sewell & Associates who contended that continued development and appraisal drilling in the GLNG dedicated areas had a reasonable likelihood of extending the 2P reserves area into most of the regions then categorised as possible reserves or 2C contingent resources.[9]

However, the contention by Netherland, Sewell & Associates that possible reserves and contingent resources would eventually be converted over to 2P reserves became increasingly difficult to justify in the face of GLNG reserve updates provided by Santos (2013). While GLNG actual 2P reserves did increase, possible reserves and contingent resources slumped with each further gas resources update.

Concerns over the lack of reserves for the Santos-led GLNG project have been longstanding, with Mathew Murphy (2010) reporting in *The Sydney Morning Herald* in September 2010 that GLNG did not yet have "adequate reserves to support it." Journalist Paddy Manning (2014) reported in February 2014:

> *Santos is in a bind. Its $20 billion-plus Gladstone LNG project is widely considered to be short of gas, with analysts scratching their heads at a lack of reserve growth and further contingent resource downgrades in its latest accounts.*

In late 2016, Geoscience Australia (2016, p. 14) reported to the Council of Australian Governments (COAG) Energy Council in relation to the three Queensland LNG exporters that:

> *APLNG and QCLNG appear best placed to utilise their native gas volumes (i.e., sourced from within their tenure holdings) to fulfil contractual requirements. Conversely, current reserve and resource figures for the GLNG project show a potential native gas shortfall.*

When asked about constructing two trains for the GLNG project in late August 2010, the then Santos Chief Executive Officer and Managing Director, David Knox, commented:

> *The key issue you've got to be absolutely confident of when you sanction trains is that you've got the full gas supply to meet your contractual obligations that you've signed up with a buyer.*
>
> *Now you should have confidence that we will sanction the second train because we will have signed up with the buyers to supply gas from that second train. In order to do it, we need to have absolute confidence ourselves that we've got all the molecules in order to fill that second train. (CQ Transcriptions, LLC., 2010)*

Then in late October 2010 Santos (2010) announced that it had reached an agreement to supply 750 PJ of gas to the GLNG project, with existing uncontracted Cooper Basin 2P reserves being the primary supply source. The agreement was conditional on the final investment decision for the GLNG second train. As a consequence of this agreement, the conventional gas reserves in the Cooper Basin will be depleted sooner than they otherwise would have been (Australian Competition and Consumer Commission, 2016, p. 60). Jim Snow (2017), Executive Director of energy consultants Oakley Greenwood, has described this agreement as the "smoking gun" for impending natural gas shortfalls in the Eastern Gas Region.

In 2016, the ACCC (2016, p. 24) observed the Santos-led GLNG had been purchasing substantial volumes of gas in the domestic market to supplement production from its inadequate reserves. In December 2016 Santos (2016a) reported on the third-party gas supply contracts that GLNG had entered, a summary of which is presented below in Table 4.

[9] Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves (Society of Petroleum Engineers, 2017, p. 13).

Table 4: GLNG Third Party Gas Supply Agreements

Supplier	Quantity PJ	From	Term
Santos	750	2015	15 years
Origin	365	2015	10 years
Origin	194	2016	5 years
Other Suppliers	85	2015 2016	7 years 21 Months
Meridian JV	445	2016	20 years
AGL	254	2017	11 years
Senex	340	2018	20 years
Combabula	52	2015	20 years
Spring Gully	17	2015	20 years
Uncommitted Combabula / Spring Gully / Ramyard	321	2015	15 years +

Source: Santos (2016a, p. 64).

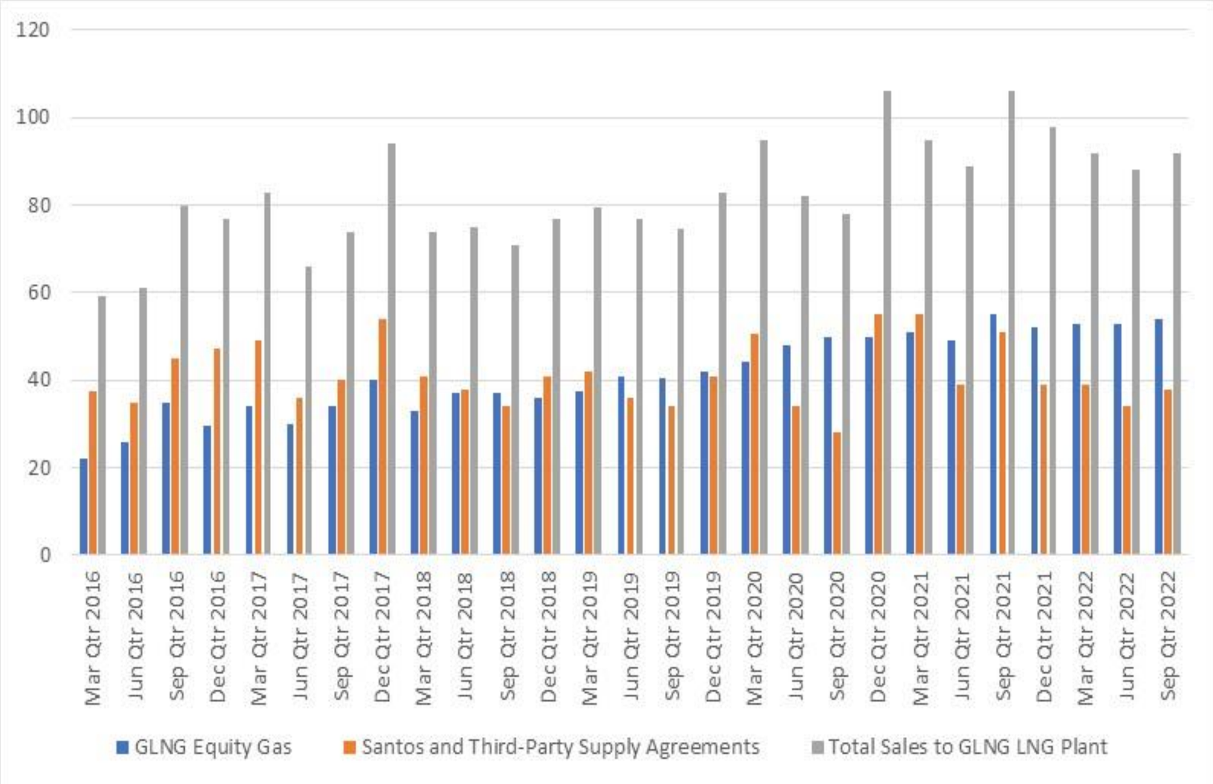
The available evidence suggests Santos did not in fact possess all the *molecules* it required to fill the second train for the GLNG project as suggested by its former Managing Director and Chief Executive Officer. Furthermore, the number of third party gas supply agreements entered into by GLNG commencing in 2010 also directly repudiates claims made by Santos (2009, p. 6.15.11) in the GLNG *Environmental Impact Statement* in 2009:

> ***The project may initially supply domestic gas markets, but it is not diverting gas from local markets to export markets.*** *The project's supply of gas to the domestic market is uncertain at this stage. Options to manage ramp up gas and any gas that is surplus to the requirements of the LNG facility include a range of commercial and technical possibilities. Therefore the project has no direct implications for domestic gas prices.* ***The gas to supply the LNG facility will come from newly developed CSG fields.*** *The amount of gas is very small relative to the identified conventional and CSG fields reserves available to supply the Australia east gas fields.* ***It is therefore unlikely to contribute to a future shortage of gas in the domestic market.***[10]

As a matter of fact, the Santos-led GLNG project has diverted natural gas from domestic users to export markets, as it has not exclusively relied upon newly developed CSG fields for its gas supply, and it has been the major contributor towards any impending natural gas shortfalls within the Eastern Gas Region. The sources of gas for the GLNG LNG project are outlined in Figure 12 below.

[10] Emphasis not in the original document.

Figure 12: Sales of Gas to GLNG LNG Plant – March Quarter 2016 to June Quarter 2022 (PJ)



Source: Santos (2022c).

The ACCC (2022a, p. 22) takes the approach that any domestic gas produced by a third party and purchased by an LNG exporter is a withdrawal from the domestic market. In turn, the ACCC has observed that GLNG along with QCLNG are net withdrawers from the Eastern Gas Region, while APLNG is a net contributor.

According to the ACCC (2022a, p. 22), in gross terms there were just under 200 PJ withdrawn in 2020 and just over 200 PJ withdrawn in 2021 collectively from the Eastern Gas Region by the LNG exporters. The vast majority of these withdrawals have been made by GLNG, with withdrawals of almost 168 PJ of gas in 2020, and 184 PJ in 2021. In turn, this suggests GLNG is responsible for between 80 to 90% of the gross gas withdrawals from the Eastern Gas Region by the LNG exporters during 2020 and 2021.

In an article entitled *Why Santos owns the gas crisis*, *The Australian Financial Review* columnist Matthew Stevens (2017) put responsibility for any impending natural gas shortfalls within the Eastern Gas Region squarely at the feet of Santos and the GLNG project:

> *The facts of the role that Santos and its partners in the GLNG project have played in delivering the nation to gas shortage are well appreciated and incontrovertible.*
>
> *Despite some internal debate, Team Santos decided to proceed with the construction of a second train at its Curtis Island liquefied natural gas plant.*
>
> *That debate was triggered by the fact that Santos did not have enough gas to justify that investment.*

Similarly, business journalist for *The Australian* newspaper Matt Chambers (2017) wrote:

> *Rightly or wrongly, GLNG and its past investment decisions are being painted by many as the major culprit in the east coast gas crisis.*

…

GLNG is in its gas-short position after it approved two production trains at Gladstone in 2011 without having enough gas reserves to supply them.

Apparently not willing to let a good crisis go to waste, Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its NGP, without acknowledging the central role it played in creating the very circumstances that it now claims the NGP will address.

Santos has also acknowledged that the company's actions have been blamed for any impending gas shortages in the Eastern Gas Region, with current Santos Chief Executive Kevin Gallagher (2019, p. 4) telling the 2019 APPEA conference in late May 2019:

It has been said that not all six LNG trains on Curtis Island should have proceeded and that Santos should not have built the second of its two trains.

That second train has sometimes been blamed for the tight east coast domestic gas market today.

4.3 Addressing the Impending Gas Shortfall

Following warnings by the ACCC (2022a, p. 7) that there could be a gas shortfall in the Eastern Gas Region by 2023, the Commonwealth Government has signed a new Heads of Agreement with the LNG Exporters to prevent a gas supply shortfall and secured new commitments from LNG exporters that will lead to an extra 157 PJ being supplied to the domestic market in 2023 (King, 2022). While the intervention by the Commonwealth Government may avert a supply shortfall during 2023, it has not addressed, however, the underlying problem in the medium to longer term.

If there is an impending shortfall of gas in the Eastern Gas Region, then increased gas supply and exports from Queensland could potentially make up some of the shortfall in the southern states (Bethune & Wilkinson, 2019, p. 521). However, there are infrastructure limitations on how much gas can be exported from Queensland to the southern states. The existing pipeline infrastructure cannot move more than 140 PJ per annum without more investment.

Additional investment in pipeline infrastructure will face several challenges (Bethune & Wilkinson, 2019, p. 521). First, there are no low cost 2P gas reserves left available to supply a pipeline long-term for the southern states. Second, while CSG from the Surat and Bowen Basins can meet some of the southern shortfall, the period before the decline of the CSG fields is only a few years away and not sufficient to underwrite further pipeline investments unless gas already committed to the LNG export projects is redirected toward domestic users (Bethune & Wilkinson, 2019, p. 521). Essentially, CSG reserves developed for export in Queensland are not sufficient to supply both the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).

While there has been a response from gas producers in the form of new gas developments, the currently approved projects and near-term proposals are mostly small in scale and may not be able to fill the gap being created by declining reserves in large historic gas fields (Collins, Cockerill, & Rasheed, 2019, p. 542).

There are currently five LNG import terminals proposed for the Eastern Gas Region. However, only one project has taken the final investment decision to proceed and only one of the other projects has all regulatory approvals.

Construction has been committed for the floating LNG import terminal at Port Kembla, the Port Kembla Energy Terminal (PKET) (Australian Energy Market Operator, 2022a, p. 56). The project developer, Australian Industrial Energy Pty Ltd (AIE) signed a critical lease for up to 25 years with NSW Ports for the terminal site in November 2020 (Australian Industrial Energy Pty Ltd and NSW

Ports, 2020). Also in November 2020, AIE (2020) signed a Memorandum of Understanding (MOU) with energy infrastructure company Jemena to connect the PKET with the Eastern Gas Pipeline (EGP). As part of the MOU, Jemena intends to construct a 12km underground pipeline capable of transferring gas from the PKET directly into the EGP – the major natural gas pipeline between Victoria and NSW.

In November 2021 AIE (Australian Industrial Energy Pty Ltd, 2021) signed a long-term charterparty agreement with energy infrastructure and transport provider Höegh LNG to supply the first Floating Storage and Regasification Unit (FSRU) to operate at the PKET. Under the agreement, the Höegh Galleon will service the Terminal as the FRSU, that is essentially a floating LNG import terminal.

Construction for PKET is anticipated to be completed in late 2023 in the anticipation that it will commence supplying gas in the winter of 2024, although there is some uncertainty surrounding customer contracted volumes, which may not be sufficient to justify the relocation and operation of the FSRU (Australian Energy Market Operator, 2022a, p. 56).

EnergyAustralia, Australia's third-largest electricity and gas retailer has agreed to purchase 15 PJ of gas per year from PKET (2019). However, the other two major electricity and gas retailers, Origin Energy and AGL Energy, as well as other potential customers for the terminal, are so far holding off from committing as they examined the needs of their customers and found no urgent need for new gas supplies (Macdonald-Smith, 2022a). Apparently, the other gas retailers say their customers do not need more gas until 2026, despite the current tight market (Macdonald-Smith, 2022). There have also been press reports that the other major gas retailers have so far baulked at the prices demanded for gas by PKET (Macdonald-Smith, 2022e).

PKET needs to lock in customers to use the LNG import terminal to avoid losing the Hoegh Galleon that it has tentatively agreed to contract from Norway's Hoegh LNG (Macdonald-Smith, 2022). In this regard, the ACCC has observed:

> *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.*

AIE has planning approval to import up to 115 PJ of LNG per annum at PKET (GHD, 2019, p. 15). With a proposed capacity of up to 500 terajoules a day, the terminal could meet more than 75% of the gas needs of NSW, although most cargoes would arrive in the high-demand winter months, dovetailing with the typically lower demand in LNG markets in the northern summer (Macdonald-Smith, 2022b).

Venice Energy announced in March 2022 that it is accelerating the development of its proposed LNG import terminal in Port Adelaide, with construction expected to commence in the second half of 2022 pending a final investment decision (Pekic, 2022). This follows a decision by the South Australian Government to approve the development of the facility, making it the second LNG import terminal to have received the relevant approvals in Australia. In July 2022 Venice Energy (2022) has signed a memorandum of understanding with Japanese trading and investment house, Marubeni, to create a joint venture partnership for development of the LNG terminal.

4.4 Competitiveness of Narrabri Gas Compared to LNG Imports

Both PKET and the NGP have the capacity to supply in excess of 60% of NSW's current demand for gas. On this basis, PKET is competing directly against the NGP for commercial viability with only one project likely to proceed in the medium term. Whichever project proceeds will depend on whoever is able to secure more long-term supply agreements before making a final investment decision (FID) to proceed. As EnergyQuest analyst Graeme Bethune has said in relation to the NGP, but which is equally applicable to the PKET:

> *Buyers will sign up if it is competitive; if it isn't they won't and it won't go ahead. (Fowler, 2020)*

In January 2020, Santos Chief Executive Kevin Gallagher declared:

> *If we can develop Narrabri gas, it will be the most competitively-priced gas for NSW customers, and it will always be cheaper than LNG imports, especially when gas prices are high in Asia. (Macdonald-Smith, 2020)*

Similarly, in its submission to the NSW Legislative Council inquiry into the implementation of the recommendations contained in the NSW Chief Scientist's Independent Review of Coal Seam Gas Activities in NSW, Santos (2019, p. 5) contended that:

> *While import terminals may add supply to the market, imported gas will not be cheaper than gas developed within NSW.*

More recently, Santos (2022b) has reiterated the potential prices benefits arising from the development of the NGP in the following terms:

> *The cheapest gas supply will always be the gas on your doorstep because that reduces transport, storage and other handling costs.*

At the end of September 2022, Santos CEO Kevin Gallagher went even further when he declared:

> *Gas from Narrabri will always be cheaper for NSW customers than gas imported from other states or overseas. (Santos Ltd, 2022a)*

In its 2019 Gas Statement of Opportunities report, the AEMO (2019, p. 3) asserted:

> *Continued interest in LNG import terminals, particularly in Victoria, New South Wales, and South Australia, would be expected to help relieve pressure on meeting southern gas demand during peak periods and assist in reducing pipeline constraints, but may do little to ease gas pricing pressures.*

Rather tellingly, the AEMO has chosen not to repeat the same reflection on the price competitiveness of LNG imports in any of its subsequent Gas Statement of Opportunities reports.

Energy Consultant Nicholas Mumford (2019, p. 666) has observed that the clear commercial reality of gas supply sourced from an LNG import terminal is that it can only be supported by high gas prices. Given the Eastern Gas Region is dominated by a *de facto* cartel, arguably high gas prices have already been locked in regardless and have made LNG imports a commercial possibility.

In the current challenging environment in relation to global energy markets, natural gas supply from an LNG import terminal operating in the Eastern Gas Region would appear to be prohibitively expensive at present. During October 2022, LNG spot prices in Asia were trading in excess of $66 per GJ (Macdonald-Smith & Fowler, 2022), while oil-linked contract prices in Asia would be around half this amount. No one is likely to enter into either short- or long-term gas supply contracts with an LNG import terminal operator in the Eastern Gas Region based on these prices.

Presently, the NGP is far more likely to proceed in the medium term if the current environment persists as the PKET is likely to lose its access to the Hoegh Galleon, potentially delaying the project for many years. Indeed, there have been reports that PKET has sought Commonwealth and state government assistance in bringing prospective customers on board, suggesting the project is on the brink of collapse (Macdonald-Smith, 2022). In late June 2022 it was suggested that PKET had only several weeks available to it in order to secure the Hoegh Galleon, otherwise the vessel could be redirected to Europe.

Santos CEO Kevin Gallagher (2022) recently intimated in the Santos 2022 investor day briefing in November 2022 that Santos could easily find long-term customers for gas from the NGP:

> *And I can tell you, we are well over 100% subscribed by buyers who want that gas, and they just don't want it for 1 year or 2 years, we've got long-term offers on the table or expressions of interest … on the table from buyers for 10 plus years, 10, 15 years which is not the norm in the domestic gas market.*

On the other hand, with domestic gas prices at record highs in the Eastern Gas Region, major prospective gas customers will be unlikely to rush into signing new GSAs for gas from the NGP. Further, various parties have queried whether the NGP will actually proceed. Former prime minister Malcolm Turnbull has expressed doubt that the NGP will be financially viable, saying the gas is too expensive to extract (Fowler, 2020). According to Mr Turnbull:

> *Bottom line, it just doesn't stack up economically.*

The ACCC (2022, p. 42) has warned the production of unconventional gas from the Bowen, McArthur, Galilee and Gunnedah basins face a number of technical and commercial barriers. In turn, the ACCC has warned:

> *It could therefore be some time before these resources are considered commercially recoverable and capable of being supplied into the market (if at all).*

The factors contributing to recent gas price rises internationally will probably abate in time and high prices are unlikely to persist. An outbreak of peace and a political agreement in the Ukraine could see Russian gas supplies return to international market relatively quickly (Hodge, 2022, p. 4).

Further, new projects coming online in both the United States and Qatar are expected to significantly increase LNG export capacity. The LNG production capacity in the United States is expected to increase from its current level of 80 Mt per annum (Mtpa) to 114 Mtpa by the end of 2024 (Department of Industry, Science and Resources, 2022a, p. 82). There are also now proposals for new LNG facilities (preFID) in the United States that have a combined liquefaction capacity of over 172 Mtpa. Qatar's LNG export capacity is expected to rise from its current level of around 77 Mtpa to around 107 Mtpa by 2026. (Department of Industry, Science and Resources, 2022a, p. 82). This is expected to increase to around 126 Mtpa by 2027 (Reuters, 2022). New production capacity in turn will put downward pressure of global LNG prices.

If global energy markets return to conditions experienced prior to 2020, then there are various reasons why LNG imports might be still competitive with pipeline imports from Queensland.

First, the cost of production in Queensland is relatively high (Department of Industry, Innovation and Science, 2018, p. 100). The vast majority of the gas produced in Queensland is CSG where production requires drilling hundreds of new wells per year — something conventional gas does not require — which adds to the cost of production. Gas in many other parts of the world — be it US shale gas or conventional gas in Qatar or off Australia's North West coast — has lower production costs.

Second, transporting gas via pipeline from Queensland to the southern states is relatively costly (Department of Industry, Innovation and Science, 2018, p. 100). The current published transmission costs from Wallumbilla to Sydney or to Culcairn for further transmission into Victoria is $2.14 per GJ (APA Group, 2022). On the other hand, it has previously been estimated that the costs per GJ of regasification for an FSRU importing up to 100 PJs per annum could be in range of between $0.60 - $1.50 per GJ (Department of Industry, Innovation and Science, 2018, p. 105).

It has been suggested that PKET will source LNG from Australian oil and gas company Woodside Energy (from WA) as well as from the United States (Williams, 2020). The sea freight voyage between Sabine Pass, the largest US LNG export terminal on the US Gulf Coast, and Tokyo, is comparable to the voyage between Sabine Pass and Port Kembla. The Japan-Korea Marker (JKM), is the most widely quoted measure of the prices of spot LNG trades in Asia. Another LNG spot price indicator is the Argus Northeast Asia 'delivered ex-ship' (des) (ANEA) (produced by Argus Media) that covers LNG spot prices for Japan, South Korea, Taiwan and China. On this basis, the ANEA provides a reasonable proxy for the cost of importing LNG to Port Kembla.

Before global energy markets were affected by the economic downturn associated with COVID-19 and the more recent war in the Ukraine, the landed price of ANEA from March 2019 until October 2019, plus a $1.45 per GJ allowance for regasification and pipeline transfer, was less than the Sydney wholesale gas spot price.

5. N2IP Projects Linked to the NGP

5.1 Long Term Supply Contracts for the NGP

Even if the current environment in relation to global energy markets were to persist, thereby indefinitely delaying the opening of the PKET, there is absolutely no guarantee the NGP would proceed in any event.

Santos still needs to secure long term supply contracts with gas users to underwrite the capital investment before taking a decision to proceed with the NGP. However, ongoing and persistently high gas prices for domestic users in the Eastern Gas Region is likely to lead to demand destruction. Demand destruction is not part of that normal supply and demand cycle (DTN Team, 2022). Instead, it occurs when persistent high prices or limited supply for a product reduces demand leading to a *permanent, widespread abandonment* of the product. Continued high prices in the Eastern Gas Region are likely to lead to demand destruction as industrial users and GPG seek alternatives to gas supply or simply cease operations.

In August 2022 the ACCC warned of potential demand destruction:

> *We spoke to C&I users between March and June 2022 about their experiences seeking gas supply for 2023, as well as current pricing in the domestic spot markets in May/June 2022. C&I users have expressed great concern about the impact of recent price rises, if they continue. Some users noted closure of operations was becoming a very real possibility in the short term and more significant demand destruction was likely over the longer term. (Australian Competition and Consumer Commission, 2022a, p. 6)*

> *In our most recent C&I user survey, some users noted they had received offers above what it would cost them to switch their plant operations the use of alternative fuels, such as biomethane or diesel. Spot exposed manufacturers have also considered ceasing operations ... If high international and domestic spot prices persist and flow through to long term contracts, the prospect of C&I closure and longer-term demand destruction look increasingly likely. (Australian Competition and Consumer Commission, 2022a, p. 42)*

Australian Industry Group chief executive Innes Willox has warned the surge in gas prices could lead to "job losses, deferred investment and possible plant closures" (Brown, 2022). In October 2022, columnist Jennifer Hewett (2022) warned in *The Australian Financial Review* that:

> *Energy-intensive manufacturers on the east coast are sounding increasingly desperate about their ability to survive, let alone thrive.*

So far, Santos has entered into tentative supply arrangements with three potential manufacturers who may also participate in the N2IP, those being:

- Perdaman for the production of ammonia and ammonium nitrate
- Brickworks for the manufacture of bricks
- Natural Soda for the production of baking soda.

Also, in May 2019 Santos (2019c) announced that it had signed non-binding memoranda of understanding with Weston Energy for the supply of natural gas from the NGP. Under the proposed transactions, Santos would supply Weston Energy with 10 PJ per year for 10 years from Narrabri gas, commencing no earlier than 2023. The supply of Narrabri gas was subject to a final investment decision, negotiation and execution of a definitive GSA.

However, the Australian Energy Market Operator (AEMO) suspended Weston Energy from trading in all hubs of the Short Term Trading Market and the Victorian Domestic Wholesale Gas Market with effect from 24 May 2022, due to Weston being unable to meet the liquidity requirements to trade in these markets (Australian Competition and Consumer Commission, 2022a, p. 13n). Weston's primary business model involved providing commercial and industrial users with access to gas through buying at and passing through facilitated market spot prices (Australian Competition and Consumer Commission, 2022a, p. 61). At the time of their suspension, Weston supplied more than 400 commercial and industrial gas users. Weston Energy ceased its gas-trading operations in May 2022 after becoming unable to finance cash flow requirements of its trading portfolio after gas prices had tripled since the beginning of 2022 (Macdonald-Smith, 2022d).

5.2 Climate Change Policy and Stranded Asset Risks

Methane, the largest component of processed natural gas, has been classified as a greenhouse gas (GHG), so its presence in the atmosphere affects the earth's temperature and climate system (U.S. Environmental Protection Agency, 2022). Methane is the second most abundant anthropogenic GHG after carbon dioxide (CO_2), accounting for about 20% of global emissions. Methane is more than 25 times as potent as carbon dioxide at trapping heat in the atmosphere.

Parties to the 2015 Paris Agreement pledged to limit global warming to well below 2°C and to pursue efforts to limit the temperature increase to 1.5°C relative to pre-industrial times (Welsby, Price, Pye, & Ekins, 2021, p. 230). It has been estimated that nearly 60% of oil and methane gas, and 90% of coal must remain unextracted to allow for a 50% probability of limiting warming to 1.5°C (Welsby, Price, Pye, & Ekins, 2021). This means that oil and gas production must decline globally by 3% each year until 2050. This implies that most regions must reach peak production during the next decade, rendering many operational and planned fossil fuel projects unviable.

2021 saw a surge of corporate concerns about net zero by 2050 and decarbonisation of the economy (Lewis Grey Advisory, 2021, p. 8). The former Morrison Commonwealth Government committed to the net zero by 2050 target shortly before the 26th UN Climate Change Conference of the Parties (COP26) in Glasgow in November 2021. [11] The Albanese Commonwealth Government elected in May 2022 has committed to reducing Australia's greenhouse gas emissions by 43% by 2030 – which will become Australia's target under the Paris Agreement, keeping Australia on track to achieve net zero by 2050 (Australian Labor Party, 2021). Furthermore, under the Albanese Commonwealth Government Australia joined the Global Methane Pledge in October 2022, a voluntary commitment with 122 signatories including the United States, United Kingdom and the European Union working collectively to reduce global methane emissions across all sectors by at least 30% below 2020 levels by 2030 (Bowen, 2022). Signatories to the non-binding pledge commit to taking a range of domestic actions such as standards for reducing emissions in the energy and waste sectors.

[11] Net zero means cutting greenhouse gas emissions to as close to zero as possible, with any remaining emissions re-absorbed from the atmosphere, by oceans and forests (United Nations, n.d.). Net zero emissions means that all anthropogenic greenhouse gas emissions must be removed from the atmosphere through reduction measures (myclimate, n.d.).

Stranded assets are defined as assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities (Caldecott, Dericks, Pfeiffer, & Astudillo, 2017, p. 04). These include physical (e.g., fossil fuel equipment, infrastructure), financial (e.g., equity and debt); natural (e.g., fossil fuel resources); human (e.g. expertise, jobs); and social (e.g. networks and communities) assets (Rempel & Gupta, 2021). If physical stranded assets are decommissioned prematurely, then financial stranded assets would subsequently arise as revenues are lost and debts/equity remain on balance sheets; dependent jobs would be stranded (human assets) and communities dismantled (social assets), in addition to the resources themselves that potentially are no longer viable for commercialisation (natural assets).

Asset stranding has always been part-and-parcel of the creative destruction seen in any market economy (Caldecott, Dericks, Pfeiffer, & Astudillo, 2017, p. 07). Physical assets often become stranded in the face of technological change, rendering them economically obsolete. However, in recent years, the issue of stranded assets caused by environmental factors, such as climate change and society's attitudes towards it, has become increasingly high profile (Caldecott, Dericks, Pfeiffer, & Astudillo, 2017, p. 04). Several factors could lead to assets becoming stranded (Matikainen & Soubeyran, 2022). These include: new government regulations that limit the use of fossil fuels and carbon dioxide emissions; and a change in demand, such as a shift towards renewable energy because of lower energy costs. Moving forward, the risks of fossil fuel asset stranding could come from improvements in energy efficiency, as well as advancements in renewables and battery storage (Paun, Knight, & Chan, 2015, p. 1).

New natural gas projects such as the NGP run the risk of becoming stranded due to regulatory requirements that constrain carbon dioxide emissions as well as improvements in alternative energy technology.

Those who have invested in fossil fuel companies, including people who have purchased the companies' stocks or bonds, are most at risk, with cascading impacts on companies that use fossil fuels (Matikainen & Soubeyran, 2022). This includes a wide variety of people and institutions such as individual investors, banks, superannuation or pension funds, insurance companies and universities, among others. Beyond investors, the early phasing out of fossil fuel-based infrastructure could affect workers and communities that rely on the infrastructure for jobs and income.

Risk and exposure to stranded assets is often compounded because of the problems of path dependency and short-term decision-making biases (Caldecott, Howarth, & McSharry, 2013, p. 14). These forces describe the tendency of firms and decision-makers to invest in reinforcing and protecting their existing asset base and business models, rather than adapting to a new forward looking strategic environment.

Based on analysis of available well results from the NGP, the average CO_2 content of CSG from the NGP is in the range of between 25% to 30% (Grogan, 2020). This compares to CO_2 content of around 3% in shale gas extracted from the Beetaloo Sub-basin (Tamboran Resources, 2021, p. 6).

Fugitive emissions are defined as unintended gas or vapour emissions from leaks or other faults in pressurised equipment during industrial processes, resulting in air pollution and potential economic loss (O'Kane, 2013, p. 91). Methane is the primary fugitive emission emitted during natural gas extraction, processing and delivery. Fugitive emissions from natural gas can arise during various stages, including production; processing and transport from vented emissions and flaring gas; and gas leakages in pipes, valves and other equipment.

According to the Sixth Assessment Report (AR6) of the International Intergovernmental Panel on Climate Change (IPCC), fossilised methane has a Global Warming Potential (GWP) 29.8 times that of CO_2 (plus or minus 11).[12] GWPs are used to convert masses of different GHGs into a single carbon

[12] See Forster, et al., (2021, p. 1017).

dioxide-equivalent metric (CO_2-e). In broad terms, multiplying a mass of a particular gas by its GWP gives the mass of CO_2 emissions that would produce the same warming effect over a 100 year period.

The estimation of methane emissions from the gas industry is generally not done through direct emission measurements (Department of the Environment and Energy, 2017, p. 5). Instead, emission estimates are prepared using sets of model parameters or emission factors derived from sample datasets recorded in published studies. No country directly monitors all fugitive emissions from the gas industry. The Final Report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (Pepper, et al., 2018, pp. 215-216) estimated that 1.7% of methane was emitted between extraction and delivery across the U.S. natural gas supply chain, including from both conventional and unconventional gas wells.

The CSIRO (2020) has previously measured emissions at 43 CSG wells – 37 in Queensland and six in New South Wales. This study found that while only three out of the 43 CSG wells showed no emissions, the remainder generally had rates of emission that were very low, especially when compared to the volume of gas produced from the wells. On this basis, an average fugitive emissions representing 1.7% of total raw gas production does not appear to be unreasonable.

Venting is the deliberate or routine release of natural gas into the atmosphere (Bradbury, Clement, & Down, 2015, p. 4). This includes the emissions of non-hydrocarbon gases (including CO_2), which are removed from the raw natural gas during processing. Non-hydrocarbon gases make up part of the raw natural gas that is extracted at wellheads, and they are removed through processing to reduce impurities and to raise the hydrocarbon content of pipeline-quality natural gas (Bradbury, Clement, & Down, 2015, p. 8). Non-hydrocarbon gases removed during processing are typically vented into the atmosphere, which can include venting of CO_2.

Assuming 73 PJ of natural gas production from the NGP per annum, CO_2 content of 25% in the CSG, fugitive emissions of 1.7% of natural gas production, with CO_2 venting into the atmosphere during processing, suggests CO_2-e emission from the NGP will be in excess of 1.1 million tonnes (Mt) per annum.

The Commonwealth Government's safeguard mechanism commenced on 1 July 2016 and applies to facilities that emit more than 100,000 tonnes of CO_2-e covered emissions in a financial year (Clean Energy Regulator, 2020b). The safeguard mechanism applies only to covered emissions, including direct emissions from fugitive emissions and emissions from fuel combustion, waste disposal and industrial process such as cement and steel making. Emissions baselines represent the reference point against which emissions performance will be measured under the safeguard mechanism. A safeguard facility must keep its net emissions levels at or below its baseline.

Emitters with a facility that has, or is likely to, exceed its baseline can reduce the facility's net emissions by purchasing and surrendering Australian carbon credit units (ACCUs) to offset their emissions (Clean Energy Regulator, 2020a). An ACCU are issued by the Clean Energy Regulator (2020) and represents one tonne of CO_2-e stored or avoided by a project. ACCUs provide a way for large CO_2 emitters to offset their emissions by buying the credits either on the spot market or via long-term contracts (Fowler, 2022).

The imposition of the safeguard mechanism on the NGP coupled with the purchase of ACCUs to offset CO_2-e emissions would impose an additional cost on NGP gas production of almost $35 million per annum based on the current spot price for an ACCU of $31.50 per tonne of CO_2-e. The requirement to offset CO_2-e emissions from the NGP would increase the cost of gas by $0.48 per GJ, $0.16 per GJ of which comes from venting of CO_2 during processing. Assuming similar fugitive emissions from a similar sized gas development in the Beetaloo Sub-basin, the venting of CO_2 during natural gas processing would only impose an additional cost burden on Beetaloo Sub-basin gas of $0.02 per GJ.

Companies extracting oil, gas, and coal could be affected by stranded assets as a result of the low-carbon dioxide transition, but it is not only the fossil fuel sector that is at risk (Matikainen & Soubeyran, 2022). Other sectors that use fossil fuels as inputs for production or are otherwise energy – or carbon dioxide-intensive, could also be impacted. As the world transitions away from high-carbon dioxide emitting activities, all technologies and investments that cannot be adapted to low-carbon dioxide and zero-emission modes could face stranding. In turn, developing the N2IP and a Special Activation Precinct (SAP) predicated on natural gas supply from the NGP exposes participants dependent upon gas to the heightened risk of having their assets stranded as well. We will now consider the economic prospects and viability of N2IP-related projects, with and without the NGP.

6. Perdaman Ammonium Nitrate Project

6.1 Arrangements between Perdaman and Santos

In late February 2019, Santos (2019a) announced that it had entered into a non-binding agreement with Perdaman for the supply of 14.5 PJ of natural gas per annum over 20 years, subject to a final investment decision for the NGP. Under the agreement, gas would be supplied to a proposed new ammonium nitrate plant near Narrabri to produce fertiliser for agribusiness. The plant would be developed in parallel with the NaGP to use appraisal and early development gas. It was asserted the ammonium nitrate plant would be expected to support 700 jobs during construction and another 100 direct and 100 indirect ongoing jobs during operations.

Commenting in relation to Perdaman’s tentative GSA with Santos, Founding Chairman and Managing Director, Mr Vikas Rambal said in February 2019 that:

> *We will bring new competition, which is always good for prices, to the fertiliser market in NSW and that will be good for farmers in the region. (Santos Ltd, 2019a)*

On 2 August 2020 Perdaman and Santos (2020) signed a heads of agreement for the further study and design of Perdaman’s proposed ammonia production facility using Narrabri natural gas. This Pre-FEED (front-end engineering and design) study was the next step in the development of a chemical and fertiliser facility near Narrabri, which will use appraisal and early development gas.

6.2 Ammonia

Ammonia is composed of one nitrogen atom bonded to three hydrogen atoms (NH_3). It is a translucent product with a distinctive strong odour (Amhamed, et al., 2022, p. 408). Ammonia is the starting point for all mineral nitrogen fertilisers (International Energy Agency, 2021, p. 15).

Fertilisers are a source of nutrients used by plants to grow, constituting an integral input to the world’s agricultural systems (International Energy Agency, 2021, p. 17). The primary purpose of fertilisers is to achieve and maintain high crop yields and replenish soils with the nutrients that are depleted when plants grow (International Energy Agency, 2021, p. 20).

Plants obtain carbon, hydrogen and oxygen directly from water and the atmosphere (International Energy Agency, 2021, p. 17). Nutrients are also sourced from the environment, with fertilisers being used to supplement those that naturally occur in a given locality. While the diverse range of plant species cultivated for human use require a wide range of nutrients, three key macronutrients are essential to virtually all plant life: nitrogen (N), phosphorus (P) and potassium (K). Within the agricultural sector, nitrogen is consumed in the largest volume of the three nutrient categories.

While the raw ingredients to produce phosphorus and potassium fertilisers are sourced from deposits of naturally occurring minerals in the earth’s crust, the nitrogen in mineral nitrogen fertilisers is sourced from air (International Energy Agency, 2021, pp. 17-18). Nitrogen is the most abundant element in the atmosphere, accounting for 78% in the form of dinitrogen (N_2) (International Energy Agency, 2021, p. 18). However, most plants are unable to absorb it directly due to its strong triple bond and require reactive nitrogen compounds (ammonium and nitrate) to be present in the soil. Mineral nitrogen fertilisers comprise a group of products that deliver nitrogen in plant-available form to soils and aquacultures.

While ammonia can be directly applied to pastures, it is much more commonly converted to urea and other nitrogen fertiliser products before use.

Just over 2% of total ammonia demand is for direct application to pastures (International Energy Agency, 2021, p. 27). Most ammonia is combined with other inputs to produce nitrogen-based fertilisers and industrial products in subsequent transformation steps. Urea is chief among these. The production of urea accounts for around 55% of ammonia demand, which is in turn used directly as a fertiliser (around 75%) and to produce urea ammonium nitrate (5%), the remainder being for a range of industrial applications. The other major use of ammonia is for nitric acid and ammonium nitrate production. Around 80% of the base product nitric acid is used to produce ammonium nitrate, two-thirds of which is used for fertiliser applications, including via further transformation into monoammonium and diammonium phosphate, ammonium sulphate, calcium ammonium nitrate and, in conjunction with urea, to produce urea ammonium nitrate. Tracing all of these uses of ammonia downstream to their end uses reveals that just under 70% of ammonia is used for nitrogen fertiliser applications, with the remainder being used for industrial applications.

All crops consume nitrogen, but just three cereals – wheat, rice and maize – account for over 50% of the total global demand for nitrogen fertiliser, largely because they are three of the four largest-volume crops grown globally (International Energy Agency, 2021, p. 21).

Access to affordable and abundant sources of ammonia production is critically important for a steady, economically viable supply to the global agriculture sector (Ghavam, Vahdati, Wilson, & Styring, 2021).

While ammonia is primarily used to produce nitrogen fertilisers, around 30% of global demand is for a range of industrial applications (International Energy Agency, 2021, p. 15). Ammonia is the main input to nitric acid production, which is in turn is used to make different grades of ammonium nitrate. Aside from its use as a fertiliser, ammonium nitrate is also used as an industrial explosive for mining, quarrying and tunnelling, and as an input to other chemical products. Urea is a direct derivative of ammonia. Besides its main use as a fertiliser, around a fifth of urea production is also used for a series of industrial applications. It is used as an intermediate in the manufacture of durable resins (e.g., urea formaldehyde) and as a chemical agent to reduce nitrogen oxide (NO_x) emissions from power plants and diesel engines. Ammonia is also used as an input to acrylonitrile production, which is an intermediate for a range of durable chemical products, including plastic, rubber and fibres. In the commercial refrigeration industry, liquid ammonia is the most widely used refrigerant due to its low price and high thermal performance (Amhamed, et al., 2022, p. 409). Liquified ammonia has been used as an inexpensive alkali in the stiffening of some steel-based materials, and in water purification.

Ammonia is traded around the world (International Energy Agency, 2021, p. 24). In 2019 global trade was almost 20 Mt, or about 10% of production. Principal exporting countries and regions are Russia, Trinidad and Tobago and the Middle East, while the principal importing regions and countries are the European Union, India and the United States. Urea, the single largest derivative product of ammonia, saw 28% of its total production volume traded in global markets during 2019.

Current commercial ammonia production involves two main steps: first, isolating hydrogen, and second, the Haber-Bosch process (International Energy Agency, 2021, p. 26). Steam methane reforming (SMR) is the most commonly used method for isolating hydrogen for ammonia production (Bicer, Dincer, Vezina, & Raso, 2017). The global natural gas-based ammonia production capacity is estimated to be around 132 Mt per year (International Renewable Energy Agency and Ammonia Energy Association, 2022, p. 36).

The global coal-based ammonia production capacity is estimated to be around 53 Mt (International Renewable Energy Agency and Ammonia Energy Association, 2022, p. 35). In China, the world's largest producer of synthetic ammonia, coal-based ammonia production capacity generally accounts for over 75% of production as it is better endowed with coal than natural gas (Zhao, et al., 2022).

In 2020, of the 185 Mt of ammonia produced, 72% relied on natural gas-based steam reforming, 26% on coal gasification, about 1% on oil products, and a fraction of a percentage point on electrolysis (International Energy Agency, 2021, p. 29).

Since the early 20th century, the method of production for hydrogen required to feed the Haber-Bosch process has evolved (International Energy Agency, 2021, p. 28). In the first few decades of industrial fertiliser production, electrolysis using hydropower was commonly used to produce hydrogen for ammonia synthesis via the Haber-Bosch process. A considerable proportion of fertilisers sold in Europe until the 1960s were produced at two hydropower electrolysis plants in Norway. Coal gasification was another early source of hydrogen. In the 1960s and 1970s wider availability of natural gas at competitive prices led to increasing use of natural gas-based steam reforming for hydrogen production, due to its lower overall production costs, and most of the electrolysis-based plants shut down over time (International Energy Agency, 2021, p. 29).

In the Haber-Bosch process hydrogen is reacted with nitrogen from the air at high temperature in the presence of a proper catalyst to produce ammonia (International Energy Agency, 2021, p. 26; Amhamed, et al., 2022, p. 408). When created by this process, it is known as synthetic ammonia (Amhamed, et al., 2022, p. 408).

Currently close to 100% of ammonia production obtains the required hydrogen from fossil fuel feedstocks (together with the steam used to transform them in certain process arrangements) (International Energy Agency, 2021, p. 26). Process energy, comprising fossil fuels and electricity, is needed in addition to the feedstock inputs to generate the heat and pressure required for the production process, and to separate nitrogen from the air.

Given existing methods of production are heavily reliant on access to natural gas, it has been estimated that 70 to 90% of the cost of manufacturing ammonium are related to cost of natural gas (Benner, van Lieshout, & Croezen, 2012, p. 20). In turn, the market price of ammonia has fluctuated in step with natural gas prices (Ghavam, Vahdati, Wilson, & Styring, 2021).

The Haber-Bosch process has the disadvantages of high GHG emissions and high amounts of energy usage, mainly due to its high operating pressure and temperature (Ghavam, Vahdati, Wilson, & Styring, 2021).

The CO_2 emissions resulting from ammonia production are governed by the hydrogen production step (International Energy Agency, 2022, p. 48). In 2020, global ammonia production accounted for around 2% (8.6 exajoules) of total final energy consumption and 1.3% (450 Mt) of CO_2 emissions from the energy system (40% of this energy was consumed as feedstock and the remainder as process energy).

Direct CO_2 emissions (often referred to as Scope 1 emissions) from ammonia production include both energy-related CO_2 emissions from the combustion of fossil fuels, and process CO_2 emissions that result from the difference in the carbon dioxide content between the feedstock used (typically natural gas or coal) and the ammonia produced (International Energy Agency, 2021, pp. 16-`17). There are also two categories of indirect CO_2 emissions (often referred to as Scope 2 and 3 emissions) (International Energy Agency, 2021, p. 17). The first is CO_2 emissions that are generated during the production of electricity, used directly to produce ammonia. The second is the CO_2

emissions that are released downstream during the application of carbon dioxide-containing nitrogen fertilisers, predominantly urea.

While CO_2 capture is widespread in the ammonia industry, with more than 130 Mt CO_2 captured in 2020, only a small fraction of the captured CO_2 is geologically stored (around 2 Mt CO_2 per year) (International Energy Agency, 2022, p. 47). This fraction comes from the only four large-scale ammonia carbon capture and storage (CCS) projects that are currently operating worldwide (two based in the United States, one based in Canada and one based in China), transporting CO2 via pipeline and storing it for enhanced oil recovery in nearby oil production facilities (International Energy Agency, 2022, pp. 47-48). The rest of the captured CO_2 is utilised for urea synthesis (International Energy Agency, 2022, p. 48).

The remainder of the CO_2 that is captured is used directly to produce urea (International Energy Agency, 2021, p. 28). However, this CO_2 is only temporarily sequestered in the urea and urea ammonium nitrate products – it is rereleased downstream in the agricultural sector when urea decomposes during the use phase.

In light of the targets set out by the Paris Climate Agreement and the global energy sector's ongoing transition from fossil fuels to renewables, the chemical industry is searching for innovative ways of reducing greenhouse gas emissions associated with the production of ammonia (Wang, et al., 2018). As ammonia production is currently dependent on access to natural gas and other fossil fuels that generate high GHG emissions, alternative production pathways are currently under investigation including electrochemical and biological routes (Bicer, Dincer, Vezina, & Raso, 2017).

6.3 Ammonium Nitrate

Ammonium nitrate (AN) is produced by neutralising nitric acid with ammonia (NH_3) (John O'Connor and Associates Pty Ltd, 2018, p. 11). Nitric acid is produced through the reaction of ammonia with oxygen in the presence of a catalyst. The reaction produces nitric oxides, which are dissolved in water to produce nitric acid. The reaction of ammonia with nitric acid produces an ammonium nitrate solution (ANsol).

There are three broad categories of AN:

- ANsol, which is used in the production of ammonium nitrate prills, liquid fertiliser and emulsion explosives
- Fertiliser grade ammonium nitrate (FGAN) – which are high density ammonium nitrate prills commonly used as a fertiliser but can be used in the production of emulsion explosives
- Explosive grade ammonium nitrate (EGAN) – which are low density ammonium nitrate prills used in the manufacture of explosives (Australian Competition and Consumer Commission, 2011, pp. 5-6).

In order to manufacture prills, the solution is sprayed into the top of a prilling tower, a rising air stream cools and solidifies the falling droplets into spherical balls or prills (John O'Connor and Associates Pty Ltd, 2018, p. 11). The density of the finished product is governed by the concentration of the solution. Low density AN prills are produced using a solution with a higher moisture content. The solidified prills also have a high moisture content and go through a lengthy drying process. High density prills are manufactured using a solution with a lower moisture content.

To produce a low-density product, additives are introduced prior to prilling which changes the structure of the prills during the prilling process to make it form a hollow, honeycomb type structure (John O'Connor and Associates Pty Ltd, 2018, p. 11). It is the additives that increase the internal crystalline strength of the low-density product. Coating agents are applied to stop the product clumping together, and to improve handling and storage properties.

Globally, ammonium nitrate is largely used in the manufacture of nitrogen-based fertilisers (Australian Competition and Consumer Commission, 2011, p. 6). However, the use of ammonium nitrate as a fertiliser in Australia has been significantly restricted by regulation related to national security.

Ammonium nitrate can be used in explosives and has a history of terrorist use (Department of Premier and Cabinet and Department for Administrative and Information Services, 2005, p. 1). On 25 June 2004 all Australian governments agreed on a national approach to ban access to high concentrations of ammonium nitrate (greater than 45%) which were named security sensitive ammonium nitrate (SSAN) for other than specifically authorised users. This agreement resulted in the establishment in each State and Territory of a licensing regime for the use, storage and transportation of SSAN.

While ammonium nitrate can be used as a fertiliser in agricultural applications, the market for this application in Australia is relatively small (John O'Connor and Associates Pty Ltd, 2018, p. 13). According to the Anti-Dumping Commission (2019, p. 24):

> *In Australia, ammonium nitrate is primarily used as a raw material in the production of explosives consumed by the mining and quarrying industries. Ammonium nitrate is classified as a dangerous good and has limited usage in Australia as a fertiliser, mainly due to the security protocols required for its transport and storage relative to other nitrogenous fertilisers such as urea and urea ammonium nitrate solution.*

More recently, the Anti-Dumping Commission (2022, p. 88) has reiterated that ammonium nitrate in Australia is principally used in the manufacture of explosives:

> *In Australia, ammonium nitrate is primarily used as a raw material in the production of explosives. Ammonium nitrate has limited secondary usage in Australia as a fertiliser in the agricultural sector, relative to other nitrogenous fertilisers such as urea and urea ammonium nitrate (UAN) solution.*

Ammonium nitrate fertilisers cost more than urea (per kg of nitrogen), and do not have near as good storage characteristics (Incitec Pivot Fertilisers, 2021). While they are not widely used by Australian farmers, ammonium nitrate fertilisers are used by some farmers in preference to urea where:

- A quick response is required to side or top-dressed nitrogen (as nitrate), e.g., in vegetable crops with a short growing season, and in winter forage crops where the conversion from ammonium to nitrate in the soil is slowed by cold soil temperatures.
- In rain grown crops where the potential for ammonia volatilisation losses is high, and fertilisers are to be surface applied without incorporation into the soil.

Demand for ammonium nitrate in Australia is predominantly driven by mining companies seeking to extract beneficial ores (i.e. iron and coal) from the earth (John O'Connor and Associates Pty Ltd, 2018, p. 13). Ammonium nitrate production facilities are located close to the main mining areas of the Sydney and Gunnedah basins in NSW, the Bowen Basin in Queensland, the Kalgoorlie region of Western Australia and, more recently, the Pilbara region in Western Australia.

Given that ammonium nitrate in Australia is primarily used in the manufacture of explosives rather than fertiliser, claims made by Perdaman and Santos that the Perdaman ammonium nitrate facility will exclusively manufacture fertiliser for Australian agriculture should be treated with extreme caution. It is far more likely that Perdaman is intending to build an explosives manufacturing facility at Narrabri to service the mining industry, rather than focus on the production of nitrogen-based fertilisers.

6.4 Domestic Ammonia Production and Markets for Nitrogen-Based Fertilisers and Explosives

In 2018-19, around 77% of elemental nitrogen-based fertilisers were imported (Australian Bureau of Agricultural and Resource Economics and Sciences, 2020). By volume, the most commonly used nitrogen-based fertiliser by Australian agriculture is urea. In 2019-20, 2,579 kt of urea was imported into Australia (Australian Bureau of Agricultural and Resource Economics and Sciences, 2020), while only 400.5 kt of urea was produced in Australia in the year to the end of September 2020 (Incitec Pivot, 2020). It has been estimated that Australia generally imports around 90% of its urea-based fertilisers (Fertilizer Australia, 2021; Hannam, 2021).

There is currently only one Australian ammonia producer that is exclusively focused on the production of nitrogen-based fertilisers, which is Incitec Pivot. Incitec Pivot is an Australian-based publicly listed company that manufactures and supplies fertilisers under the Incitec Pivot Fertilisers brand. Incitec Pivot operates ammonia plants at Phosphate Hill in Queensland, and Gibson Island in Brisbane, Queensland (Australian Competition and Consumer Commission, 2011, p. 4).

The Gibson Island plant currently produces more than 300,000 tonnes of ammonia each year (State Development, Infrastructure, Local Government and Planning, 2021). The Gibson Island plant is also currently Australia's only manufacturing facility for urea (Incitec Pivot Fertilisers, 2021a). However, Incitec Pivot (2021) announced in November 2021 that it would be ceasing manufacture at its Brisbane-based Gibson Island plant at the end of December 2022 after exhaustive efforts were unable to secure an affordable long-term gas supply from Australian gas producers. In late 2021, Incitec Pivot conducted a request for proposal (RFP), approaching 13 parties seeking to contract 13.8 PJ per annum for gas supply from mid-2023 to mid-2027 (Australian Competition and Consumer Commission, 2022a, p. 42). The RFP process resulted in 7 parties offering gas for supply for periods between 2023 to 2027. However, many of the offers provided a lower volume than IPL's total annual volume requirements and fell short of the duration requirements. Incitec Pivot proceeded to negotiate with three of the offering parties, however these negotiations did not result in any new gas supply agreement for the Gibson Island plant.

The Incitec Pivot Phosphate Hill facility manufactures final end products of monoammonium and diammonium phosphate sourcing ammonia from an inhouse ammonia plant. Pegasus estimates the ammonia production capacity of the Phosphate Hill facility is in the order to 165,000 tonnes per annum.

There is also one new ammonia facility that is currently under construction with a focus on urea production. In July 2020 Perdaman Chemicals and Fertilisers (Perdaman) (2020) signed an initial binding Heads of Agreement for the Engineering,Procurement and Construction (EPC) to develop a urea manufacturing facility in Karratha through a 50/50 joint venture between Clough of Western Australia and Saipem of Italy. Perdaman has said that it is intending to invest $4.5 billion in developing the urea facility. The Perdaman ammonia production plant being constructed as part of the urea facility will have an annual production capacity of 1,277,500 tonnes per annum (Office of the Appeals Convenor, 2022, p. 2). Perdaman (2021) has signed a 20 year off take agreement with Incitec Pivot to take up to 2.3 Mt per annum of granular urea fertiliser from the plant.

The Australian Government's Northern Australia Infrastructure Facility (NAIF) (2022) has committed $255 million for critical infrastructure supporting the Perdaman Urea Project. The NAIF commitment is being delivered through two separate loans:

- $160 million to the Pilbara Ports Authority for a new multi-user wharf and facilities at the Port of Dampier to facilitate exports
- $95 million to the Western Australia Water Corporation for the expansion of the Burrup seawater supply and brine disposal scheme that will also service the operation of Perdaman Urea Plant.

The other domestic producers of ammonia are either focused on the production of ammonium nitrate for explosives or are mixed explosives and fertiliser manufacturers. The supply of ammonium nitrate in Australia is dominated by domestic producers who supplied 92.8% from domestic production in 2019-20 and supplied another 3.6% from imported product (Anti-Dumping Commission, 2022, p. 66). Usually, non-Australian industry imports do not exceed 5% of the Australian consumption of ammonium nitrate (Anti-Dumping Commission, 2022, p. 67).

Demand for ammonium nitrate, including commercial explosives, in NSW and Queensland is primarily driven by demand from entities that mine thermal and metallurgical coal (Anti-Dumping Commission, 2022, p. 93). In WA, demand for ammonium nitrate is primarily driven by demand from mining companies that extract ores and commodities such as iron ore, gold and various other metals from the earth.

The eastern seaboard and the western seaboard market segments have distinctly different size and growth characteristics (Anti-Dumping Commission, 2021, p. 9). While the eastern seaboard market segment has been primarily experiencing a plateauing of growth, the western seaboard market has been showing stronger growth in demand.

The Yara Pilbara Fertilisers (2022) plant is one of the largest ammonia production sites in the world, with a production capability of approximately 850,000 tonnes annually. The plant is located on the Burrup Peninsula at Karratha, Western Australia, approximately 300 km from the Pilbara region (Australian Competition and Consumer Commission, 2011, p. 2). Yara Pilbara Fertilisers is the Western Australian division of Yara International, a Norwegian multinational chemical company. Yara Pilbara Fertilisers (2022) exports ammonia to domestic and global markets from the nearby port of Dampier, which is mainly used in the production of fertilisers. Yara Pilbara Nitrates is a joint venture between Yara International and Orica that operates an ammonium nitrate manufacturing facility next to and sources ammonia from the Yara Pilbara Fertilisers ammonia production plant (Yara International, 2022a).

Wesfarmers is an Australian listed public company with business operations in the retail, resources, insurance, chemicals, energy, fertilisers and industrial sectors (Australian Competition and Consumer Commission, 2011, p. 2). Wesfarmers subsidiary CSBP operates an integrated ammonia, ammonium nitrate and fertiliser complex located at Kwinana near Perth, Western Australia. The CSBP (n.d.) ammonia plant can produce up to 255,000 tonnes annually.

Orica is an Australian-based publicly listed company that operates an integrated ammonia and ammonium nitrate facility at Kooragang Island in Newcastle, New South Wales, and an ammonium nitrate facility at Yarwun, near Gladstone, in Queensland (Australian Competition and Consumer Commission, 2011, p. 3). The Kooragang Island ammonia plant has the capacity to produce approximately 360,000 tonnes of ammonia per annum (Orica, 2022).

Orica also operates a manufacturing at Yarwun in Queensland that is equipped to produce ammonium nitrate from ammonia (Anti-Dumping Commission, 2021, p. 5). The Yarwun plant sources ammonia either from the Kooragang Island plant or from third party suppliers.

While Orica does supply nitrogen-based fertilisers in Australia, it does appear to be something of business sideline with the main commercial focus of the business upon explosives.

Dyno Nobel also operates an integrated ammonia and ammonium nitrate plant at Moranbah, Queensland. Dyno Nobel is currently a fully owned subsidiary of Incitec Pivot, however, the Incitec Pivot fertiliser business and the Dyno Nobel explosives business are currently in the process of separating from each other by way of demerger (Keltie, 2022). The Moranbah ammonia plant has a production capacity of around 164,250 tonnes of ammonia per annum (GHD, 2006, p. 53).

Queensland Nitrates Pty Ltd (QNP) is a joint venture company owned by Dyno Nobel and CSBP. QNP operates an integrated ammonia, ammonium nitrate and nitric acid plant at Moura, Queensland

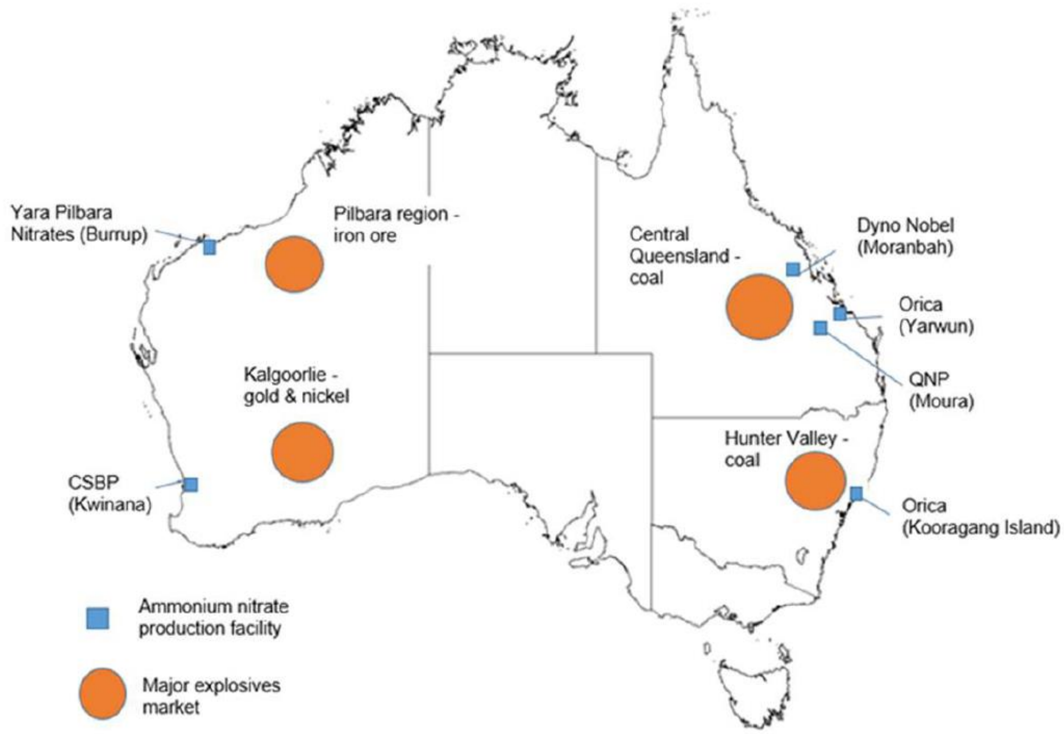
(Australian Competition and Consumer Commission, 2011, p. 4). The Moura ammonia plant has a production capacity of around 92,710 tonnes of ammonia per annum (Dyno Nobel, Incitec Pivot, and Southern Cross International, n.d.).

According to QNP, domestic suppliers of ammonium nitrate on the east coast of Australia have some excess capacity with some ammonium nitrate being supplied by both the west coast and import sources (Anti-Dumping Commission, 2022, p. 94).

Purchasers of ammonium nitrate for explosives prefer suppliers that are located within close proximity to mitigate freight costs, and to mitigate security and quality risks (Anti-Dumping Commission, 2021a). Ammonium nitrate degrades in quality the longer it is transported and therefore product performance can be compromised (Anti-Dumping Commission, 2022, p. 92). On that basis, the geographic scope of markets for the supply ammonium nitrate tends to be regional, dominated by local producers that are supplemented by a small quantity of imports. The major ammonium nitrate markets and production facilities are outlined in Figure 13 below.

While Figure 13 refers to Hunter Valley coal in relation to NSW, it is probably more accurate to refer to the geographic scope of the market as encompassing coal mines across the entire Sydney and Gunnedah basins. The Sydney Basin can be subdivided into five major coalfields namely the: Hunter, Newcastle, Southern, Western and Central coalfields (Department of Regional NSW, 2021). In the Gunnedah Basin focused around the Gunnedah, Narrabri, Boggabri and Werris Creek areas there are four open cut coal mines and one underground mine in operation (NSW Department of Planning, Industry and Environment, 2021, p. 137).

Figure 13: Major Ammonium Nitrate Markets and Production Facilities



Source: Anti-Dumping Commission (2021a).

6.5 Commercial Viability of Proposed Perdaman Ammonium Nitrate Facility

If Perdaman is actually intending to manufacture nitrogen-based fertilisers at its proposed N2IP facility, then there would appear to be plenty of market opportunity for increased domestic production at the present time for both domestic consumption and overseas exports. However, Mark Ogge (2020, p. 25) from *The Australia Institute* has declared that the Perdaman fertiliser factory is highly speculative, consisting of a non-binding agreement for the supply of gas and an agreement to undertake a study into its viability.

Rather than produce ammonium nitrate for the production of fertilisers, it appears that Perdaman is more likely to be producing ammonium nitrate for the manufacture of explosives and would target coal mining operating in the Sydney and Gunnedah basins as its prospective customer base. In turn, it presents a potential competitive threat to the Orica ammonium nitrate production facility at Kooragang Island.

As Perdaman has signed a non-binding agreement with Santos to take 14.5 PJ of natural gas per annum over 20 years from the NGP, it provides an indication of the scale of production for both ammonia and ammonium nitrate by Perdaman. Based on the use of the best available technology of SMR-based production consumes 32 GJ of natural gas per tonne of ammonia produced, then the supply of 14.5 PJ of natural gas to the proposed Perdaman ammonia plant suggests that it could produce 453,125 tonnes of ammonia per annum.[13] It would appear that Perdaman is proposing to enter the market for the provision of ammonium nitrate explosives targeting Sydney and Gunnedah basin coal production, on a scale 26% larger than incumbent Orica operating at Kooragang Island servicing the same market based on ammonia production.

The Perdaman facility would have to establish that there is a sufficient market in the region, and that it could compete with other manufacturers and imports (Ogge, 2020, p. 25). However, it is suspected that demand and supply for ammonium nitrate for Sydney and Gunnedah basin coal production is already roughly in balance, with Orica satisfying most of the demand from its Kooragang Island. For Perdaman to successfully enter this market on the scale envisaged, it would have to effectively displace Orica from the market altogether. This prospect defies credulity for a number of reasons.

There is already excess capacity for ammonium nitrate production on the east coast of Australia and demand in the Sydney and Gunnedah basins appears to be on the decline. As previously discussed above, domestic suppliers of ammonium nitrate on the east coast of Australia have some excess capacity according to QNP (Anti-Dumping Commission, 2022, p. 94). According to Orica, demand for ammonium nitrate from thermal coal is expected to experience a marginal contraction over the next 5-6 years (Anti-Dumping Commission, 2021, p. 11), the main form of coal being extracted in the Sydney and Gunnedah basins. Even if Perdaman were to successfully enter the market and displace the incumbent in Orica, it would probably be doing so on scale where it would have excess production capacity.

The production of ammonium nitrate involves high capital cost investment that carries with it high level of investment risk – particularly for wholly integrated ammonia to ammonium nitrate production facilities (John O'Connor and Associates Pty Ltd, 2018, p. 27). It has been suggested the manufacturing of ammonium is capital intensive that in turn could constitute a barrier to entry (Anti-Dumping Commission, 2022, p. 92). Fixed costs do not necessarily constitute a barrier to entry because they affect incumbents and entrants alike. However, any entry cost that is unrecoverable is a sunk cost. The need to sink costs into a new firm imposes a difference between the incremental cost and the incremental risk that are faced by an entrant and an incumbent (Baumol & Willig, 1981, p. 418). In the case of an incumbent, such funds have already been expended and they are already exposed to whatever risks the market entails (Baumol & Willig, 1981, p. 418). In contrast, the new firm must incur any entry costs on entering the market that incumbents don't bear. The need to sink costs can therefore constitute a barrier to entry. While ammonia has numerous applications, ammonium nitrate in Australia does not, therefore inferring the production of ammonium nitrate incurs significant sunk costs.

Ammonium nitrate is supplied to mines (whether to mining principals or via mining services contractors) through long-term and spot contracts (John O'Connor and Associates Pty Ltd, 2018, p.

[13] See International Energy Agency (2021, pp. 30-31).

13). Sales of ammonium nitrate are made predominantly in accordance with fixed-term contracts with only a small minority of sales being spot sales (Anti-Dumping Commission, 2022, p. 96). Fixed-term contracts are typically of 2-5 years in duration but can also be longer or shorter. The contracts are typically arranged following a tender process, and will normally specify a base price, with adjustment clauses for movements in raw material gas or ammonia prices, and certain other conditions of sale (John O'Connor and Associates Pty Ltd, 2018, p. 13). Contracts may also contain exclusivity of supply arrangements and/or 'take or pay' provisions (minimum offtake volumes stipulated in supply agreements) both of which dilute competition. According to the Anti-Dumping Commission (2016, p. 16):

> *These long term contracts underpin the business cases for maintaining or constructing ammonium nitrate manufacturing plants, enabling long term planning for known volumes of supply.*

The ACCC (2011, p. 12) has previously opined that new entry into a market for ammonium nitrate is only likely to occur in the event if that new entrant has a realistic prospect of securing foundation customer contracts. Even if Perdaman were to attempt to enter the market for supply of ammonium nitrate in the Sydney and Gunnedah basins, it is likely to initiate a competitive response from Orica to stifle it from doing so.

A combination of excess capacity on the east coast of Australia and declining demand for ammonium nitrate explosives in the Sydney and Gunnedah basins, high barriers to entry in relation to substantial sunk costs, and the need to lock in long term supply contracts makes the Perdaman proposal an extremely high-risk commercial proposition. The Perdaman proposal appears to be so fantastic that it is bordering on a hoax.

6.6 Sustainable Ammonia and Australian Production

If Perdaman did decide to pursue its proposed ammonium nitrate facility in the absence of the NGP, then there are emerging technologies for the production of ammonia that could enable it to do so.

With attention turning to developing more sustainable methods for production, ammonia is being increasingly recognised as an important, sustainable fuel for global use in the future (MacFarlane, et al., 2020, p. 1186). Applications of ammonia in heavy transport, power generation, and distributed energy storage are being actively developed. It has been contended the production of renewable ammonia will emerge through the deployment and further development off three overlapping technology generations (MacFarlane, et al., 2020, p. 1186).

Generation 1 (Gen 1) is based on an expansion of the existing Haber-Bosch ammonia production technology that also involves the use of CCS or offsets to bring the net carbon impact of the ammonia production to zero (MacFarlane, et al., 2020, p. 1188). This is also sometimes referred to as *blue ammonia*, following the colour scheme often used in relation to the development of hydrogen energy. The carbon sequestration aspect of blue ammonia production adds extra cost and plant complexity on top of the existing Haber-Bosch production technology. For this reason, it represents only a transitional solution, helping to establish a market for ammonia beyond the fertiliser and chemical industries.

SMR emits CO_2 in a concentrated form that is well-suited for CCS (The Royal Society, 2020, p. 14). While up to 90% of carbon dioxide could be captured, the upstream greenhouse gas emissions associated with natural gas extraction, limit the life-cycle emission reductions for combined SMR and CCS. For net zero carbon hydrogen production this process can only be part of a transition to a zero-carbon solution.

CCS has been subject to scepticism, with critics accusing proponents of greenwashing to extend the life of fossil fuel assets (Robertson & Mousavian, 2022). Also, failed/underperforming projects considerably outnumbered successful experiences. According to Fortescue Metals Group chair Andrew Forrest:

> *Generally the world population has every reason to be sceptical that carbon sequestration ... works because in 19 out of 20 times it's failed. (Keane, 2022)*

Generation 2 (Gen 2) renewable ammonia is also based on the existing Haber-Bosch ammonia production technology, but employs renewable, rather than fossil fuel sourced hydrogen (MacFarlane, et al., 2020, p. 1189). Gen 2 involves a device called an electrolyser, which only uses water and a renewable energy source to generate hydrogen (MacFarlane, 2021). This sustainably generated or 'green' hydrogen is fed into the Haber-Bosch process to eliminate its reliance on fossil fuels.

The advantage of Gen 2 technology is that it can be deployed for ammonia plants relying on the existing Haber-Bosch ammonia process production technology that can be transitioned to this new hydrogen supply without major disruption or mothballing (MacFarlane, et al., 2020, p. 1189). The technology has already been demonstrated on a small, practical scale by German engineering firm Siemens at the at the Rutherford Appleton Laboratory (RAL) in the UK (MacFarlane, et al., 2020; Wilkinson, 2018). A scaled-up demonstrator is being installed at the Yara ammonia plant in Karatha in northwest Western Australia (MacFarlane, 2021).

The main challenges to rolling out the Gen 2 technology are cost, of which about 85% is electricity (The Royal Society, 2020, p. 14). However, the cost of electricity in areas with abundant renewable potential has decreased dramatically over the past decade (The Royal Society, 2020, p. 15).

The capital costs of electrolysers is also a limiting factor in the roll out of this technology and the pressure is on in the research sector to find ways – cheaper catalysts, fewer components – to decrease this cost (MacFarlane, 2021). Despite the challenges, Gen 2 is predicted to be widespread by 2030 (Smart, 2021, p. 232).

Generation 3 (Gen 3) technology refers to the electroreduction of N_2 to ammonia by direct or mediated means (MacFarlane, et al., 2020, p. 1190). The Haber-Bosch process is no longer required at this level of technology. Instead, the reaction is driven by electrochemical reduction and the source of hydrogen is ultimately water. Gen 3 has a target for commercialisation by 2050 (Smart, 2021, p. 232).

Information on the use of ammonia as a hydrogen carrier and its potential applications is explored in Appendix 2.

There are currently numerous projects seeking to utilise Gen 2 technology for the production of green ammonia in Australia.

The Australian Renewable Energy Agency (ARENA) (2019) announced in September 2019 that it was providing $1.9 million in funding to QNP to assess the feasibility of the construction and operation of a renewable ammonia plant at its existing facility in Moura. The consortium, led by QNP and partners Neoen and Worley, is intending to produce 20,000 tonnes per year of ammonia from 3,600 tonnes of renewable hydrogen. The new plant would provide up to 20% of QNP's current ammonia requirements from natural gas.

It was also announced in September 2019 that Dyno Nobel would conduct a $2.7 million feasibility study to assess the potential to use renewable hydrogen to increase ammonia production at the Moranbah facility in Queensland (Incitec Pivot, 2019). The feasibility study was to examine the potential to use renewable hydrogen produced via electrolysis to increase ammonia production at its facility to meet increased demand in the region for ammonium nitrate. If feasible, the proposed solar hydrogen facility would include up to 160 MW of electrolysis capacity and a 210 MW solar farm co-located at Moranbah.

Following Incitec Pivot's announcement that it would cease ammonia production at its Gibson Island facility, it was announced in late November 2021 that Incitec Pivot had reached an agreement with Fortescue Future Industries to conduct a feasibility study to assess whether industrial-scale manufacturing of green ammonia at Gibson Island was technically and commercially feasible on an existing brownfield site (State Development, Infrastructure, Local Government and Planning, 2021). The study would investigate building a new water electrolysis facility on the site to produce around 50,000 tonnes of renewable hydrogen per year, which would then be converted into green ammonia for Australian and export markets.

In October 2022, ARENA (2022a) announced that it would support the front-end engineering and design (FEED) study for Gibson Island plant with $13.7 million in funding. The study will also consider the conversion requirements for Incitec Pivot's existing ammonia plant to utilise the renewable hydrogen production and offtake approximately 400,000 tonnes of renewable ammonia per year. If successful, the electrolyser will be one of the largest in the world, feeding renewable hydrogen into the first fully decarbonised renewable ammonia facility.

In February 2020 The Hydrogen Utility Pty Ltd (H2U) (2021, p. i) secured the land for the H2-Hub™ Gladstone Project, an industrial-scale complex for the production of green hydrogen and green ammonia to be established at Yarwun, in the Gladstone State Development Area (SDA). H2-Hub™ Gladstone is planning for a modular, staged-development approach, with up to eight process trains, each with 600 tonnes per day in ammonia production and 370 MW in electrolysis plant capacity, the first four process trains will be established as part of the Activation Stage, and the other four process trains to be established later as part of the Expansion Stage (The Hydrogen Utility, 2021, p. 2). With up to 4,800 tonnes per day in ammonia production capacity, the H2-Hub™ Gladstone Project will be one of the largest ammonia complexes worldwide.

In May 2021 Woodside Energy, IHI Corporation and Marubeni Corporation (2021) signed a Heads of Agreement to investigate the production and export of green ammonia produced from renewable hydro power in the Australian state of Tasmania. Initially, green ammonia would be produced at a small-scale hydrogen electrolysis plant. Woodside Energy would then explore options for production in the Bell Bay region in northeast Tasmania. The capacity of the proposed plant could eventually be scaled up to as much as 250 MW to produce green hydrogen as feedstock for green ammonia exports.

In June 2021, Fortescue Future Industries (2021) signed an Option Agreement with Tasmanian Ports Corporation to exclusively negotiate all land and operating access requirements for its proposed 250 megawatt (MW) green hydrogen plant in Bell Bay in Northern Tasmania, with the capacity to produce 250,000 tonnes of green ammonia per year for domestic use and international export.

In October 2021 it was announced that Japanese conglomerate Mitsui had entered into an agreement with CSBP (2021) to jointly study the commercial and technical viability of building a low carbon ammonia production plant that would include CCS provided by Mitsui. The project would examine capturing CO2 emissions from conventional ammonia production and storing it in the depleted gas fields in the Perth Basin.

Strike Energy is currently developing Project Haber, an 800,000 tonnes per annum ammonia / 1.4 million tonnes per annum urea production facility, planned to be located in the mid-West region of Western Australia (CSIRO, 2022). Strike Energy (2022) is proposing to build the manufacturing facility southeast of the town of Dongara in Western Australia, that is around 360 km north of Perth (Strike Energy, 2022). Front End Engineering and Design (FEED) early works, primarily focused on environmental approvals and consolidating the FEED basis of design have commenced (CSIRO, 2022). While the primary source of feedstock for the ammonia/urea facilities at start-up is natural gas from the South Erregulla field (undergoing field appraisal as of April 2022), the project includes the integration of an on-site electrolyser.

Initially, Strike will supply 2% of its hydrogen demand from a dedicated on-site 10MW hydrogen electrolyser (Strike Energy, 2021a). This unit is planned to be powered from nearby cost-effective wind and solar power or potentially by Strike's geothermal resources in the Perth Basin should exploration and appraisal of Strike's Mid-West Geothermal Power Project prove successful. As the renewable hydrogen market matures Strike intends to increase the import of green hydrogen up to 100% of the ammonia feedstock over the project's life.

In September 2022 it was announced that ENGIE (2022) had taken the Final Investment Decision to build one of the world's first industrial-scale renewable hydrogen projects. Scheduled for completion in 2024, the first phase of the Yuri project will produce up to 640 tonnes of renewable hydrogen per year as a zero-carbon feedstock for Yara Pilbara Fertilisers' ammonia production facility in Karratha. The $87 million Yuri project will include a 10 MW electrolyser powered by 18 MW of solar PV and supported by an 8 MW battery energy storage system. The Yuri project is being developed with the support of a $47.5 million grant from ARENA Renewable Hydrogen Deployment Fund and a $2 million grant by the Western Australian Government's Renewable Hydrogen Fund.

6.7 Sustainable Ammonia Production in Narrabri

Producing green hydrogen through an electrolyser will require access to a significant quantity of water. Theoretically, in order to produce 1 kg of hydrogen will require at least 9 litres of water (COAG Energy Council, 2019, p. xiv). In practice water requirements for hydrogen production will vary depending on factors including production method and technology, the water content of the input fuel and the need for additional water for indirect production requirements such as cooling and input water purification (COAG Energy Council, 2019, p. 12). Different electrolysis technologies have differing water consumption requirements.

In turn, hydrogen production will require secure, long-term access to water (Bergman & Johnstone, 2021). However, the sufficiency of Australia's domestic water resources and infrastructure to support scaling up to long-term, commercial-scale hydrogen production remains somewhat uncertain.

Due to uncertainty surrounding water resource availability, the COAG Energy Council's 2019 *National Hydrogen Strategy* has suggested using desalinated seawater or waste water, if available, as this may be the most feasible approach for the production of green hydrogen (COAG Energy Council, 2019, p. 10). In focus groups conducted for the development of the *National Hydrogen Strategy*, concerns were raised regarding competing uses for fresh water (COAG Energy Council, 2019, p. 61).

Perdaman could pursue its ammonium nitrate facility utilising Gen 2 technology for the production of ammonia at Narrabri, although the availability of water could be a limiting factor. There are currently three solar farms proposed in Narrabri local government area, the Narrabri South Solar Farm (60 megawatts), Silverleaf (120 megawatts) and the Wee Waa Solar Farm (55 megawatts) (Narrabri Shire Council, 2020). Furthermore, wind generated energy appears to be feasible on the Nandewar Ranges foot slopes.

7. Brickworks Brick Factory

7.1 Arrangements between Brickworks and Santos

In May 2019 Santos (2019c) announced that it had signed a non-binding memoranda of understanding with Brickworks for the supply of natural gas from the Narrabri Gas Project. Under the proposed transaction, Santos would supply Brickworks with up to 3 PJ per year of natural gas from Narrabri for seven years from 2025. The supply of Narrabri gas is subject to a final investment decision, negotiation and execution of a definitive GSA.

7.2 Brickworks Energy Supply Arrangements

The final stage in the industrial production of bricks is for dried bricks to be fired in a kiln between 10 and 40 hours, depending upon kiln type and other variables (The Brick Industry Association, 2006, p. 4). Fuel used to fire the kiln may be natural gas, coal, sawdust, methane gas from landfills or a combination of these fuels.

In September 2018 Brickworks signed a long-term natural gas supply agreement with Santos (2018) for it to supply its east coast operations through to the end of 2024. Under the supply agreement, Santos would supply up to 15PJ of natural gas to supply Brickworks' east coast operations in South Australia, Victoria, Queensland and New South Wales.

In June 2022 it was reported that Brickworks contract gas price with Santos was averaging $10 per GJ, locked in for two years, compared with the then government-mandated price cap of $40 (Kaye, 2022). According to Brickworks' Managing Director Lindsay Partridge at the time:

> *If we had to pay, when our contract rolled over, (the current spot price), we would no doubt be shutting plants down and moving production offshore. (Kaye, 2022)*

Brickworks pays just US$3 per GJ for gas in the United States, where it owns Pennsylvania-based brickmaker Glen-Gery Corp (Kaye, 2022).

In response to the prospect of facing gas prices of $20 to $30 per GJ when it comes off contract in 2025 as compared to US$3 in the United States, in October 2022, Mr Partridge further warned:

> *I don't think our market can take that. If the fools in Australia decide to wipe out industry, we'll bring product in from offshore. We'll have no choice.*
>
> *The price of the energy difference between the United States and Australia is more than the transport of bricks from the United States to Australia. It's a no-brainer. (Ludlow, 2022)*

In the current environment with soaring gas prices, it is unlikely that Brickworks would be rushing to sign a new GSA for NGP gas any time soon.

In August 2022 Brickworks along with the partner Delorean Corporation (2022) announced they were moving into the development stage of a collaboration to build and operate bioenergy plants to convert organic waste to green gas and electricity for use in Brickworks' NSW brick manufacturing operations. Brickworks said a final investment decision on whether to proceed with a $20 million-plus bioenergy plant to help power a Sydney manufacturing facility is likely to occur in the next year as it steps up work on the project with the Delorean Corporation (Evans, 2022). Brickworks managing director Lindsay Partridge said the proposed plant, if it gets the green light, would likely power about half of the needs of a brick making facility at the group's Horsley Park site in western Sydney.

According to the general manager of energy at Brickworks, Melissa Perrow, the company is already making use of a blended supply to support parts of its operations:

> *We have experience using raw biogas from two landfill facilities at two of our Sydney plants. So, we already have experience using a form of renewable gas and we're actively conducting a feasibility assessment around co-locating a biomethane renewable gas facility at our brick plants. (Grayson, 2022)*

Brickworks' Austral Bricks Horsley Park Plant 21 has used landfill gas since 2013, and Plant 23 since 2014 (Brickworks Ltd, 2022a, p. 31). The combustion of landfill gas emits 10 times less carbon than natural gas. Horsley Park used 220,073 GJ of landfill gas during 2021-22, offsetting approximately 9,925 tonnes of carbon dioxide.

Brickworks also uses carbon neutral waste sawdust from the local Tasmanian timber industry as a fuel to fire kilns to produce Austral Bricks (Tasmania) products at its Tasmanian Longford plant (Austral Bricks and Daniel Robertson, 2018). In fact, sawdust is the main fuel source at the Austral Bricks Longford plant (Brickworks Ltd, 2022a, p. 31). The site used 13,521 tonnes or 140,626 GJ of sawdust during 2021-22. While the use of sawdust is less energy efficient than natural gas, its renewable component means that net carbon dioxide emissions from the combustion of sawdust is 40 times lower than natural gas, offsetting 7,077 tonnes of carbon dioxide.

Perrow says Brickworks' focus on renewable gas stems from the fact that it is one of the largest gas consumers in Australia (Grayson, 2022). According to Ms Perrow:

> *The issue for us going forward around decarbonisation comes from the fact that we are a business that cannot electrify. You cannot electrify the brickkilns because they're burning at temperatures of over a thousand degrees.*
>
> *So, we have a very strong interest in decarbonising the gas network. We know it will take some time, but we see that this is something that we really need to do as we head towards net zero.*

During 2021-22, alternative biofuels made up 12% of Brickworks' Australian energy mix and the company continues to investigate ways to increase its biofuels content (Brickworks Ltd, 2022, p. 56).

It is entirely possible that a new Brickworks brick factory could operate at N2IP in the absence of the NGP, providing it has access to alternative fuel sources such as methane gas from landfills or sawdust. Given prevailing prices for natural gas, biofuels become an increasingly attractive and viable proposition.

8. Natural Soda Baking Soda Factory

The environmental impact statement for the NGP submitted on behalf of the proponent predicted that some 430,500 tonnes of salt waste would be produced over the life of the project, or an average of around 47 tonnes per day (about two B-double truck loads) (Cook, Carter, Fell, & Williams, 2020, p. 79). However, the Water Expert Panel established by the then NSW Department of Planning and Environment to examine and advise on water issues related to the NGP considered that salt waste production could be up to approximately 850,000 tonnes over the project life.

The 33,600 tonnes a year of salt waste from the NGP is a source of angst for locals and experts without a formal plan to dispose of it (Macdonald-Smith & Fowler, 2020).

In order to address those concerns, in July 2020 Santos (2020b) signed a Memorandum of Understanding (MOU) with Natural Soda to use salt removed from produced water as part of the NGP. Santos and Natural Soda committed to undertaking a concept study to produce sodium bicarbonate in Narrabri.

However, scientists have argued this MOU should not be seen as enough to assuage concerns that the salt could lead to dangerous contamination of ground and surface water (Moreton, 2020). According to Professor Stuart Khan, from UNSW's School of Civil and Environmental Engineering Research, the mass of salt produced from the NGP "will inevitably lead to the production of highly saline leach and an associated high risk of seriously contaminated groundwater and surface water" (Macdonald-Smith & Fowler, 2020). Professor Khan does not believe the memorandum of understanding struck between Santos and Natural Soda to take the salt provides a strong enough assurance the salt would be handled correctly. According to Professor Khan:

> *I strongly suggest that development approval be conditional upon much more than just a Memorandum of Understanding or even a detailed business case. A full-scale commercial soda ash production facility needs to be seen to be well*

> *under construction and realistic financial commitments to its completion must be in place. (Macdonald-Smith & Fowler, 2020)*

According to Mark Ogge (2020, p. 26) from *The Australia Institute*:

> *The idea of a baking soda factory using (toxic) waste salt from coal seams is little more than a thought bubble. If such a venture was viable there should already be baking soda factories attached to coal seam gas fields all over Queensland.*

The idea of taking salt waste from CSG production and turning it into useful salt products is not new. Selective salt recovery (SSR) is a unique combination of existing technologies to produce salt products from brine for potential beneficial reuse (Australian Petroleum Production and Exploration Association, 2018, p. 49).

In June 2011 Penrice Soda Holdings (Penrice) (2011), the then only domestic commercial manufacturer of baking soda, announced that it had signed of a Consortium Agreement with the water and process technologies business of GE Power & Water to provide the Australian CSG industry with a complete brine removal mechanism for its associated water. The Consortium Agreement focused on building demonstration plants to commercialise novel technology developed by Penrice.

Using water from several CSG projects, Penrice had previously conducted laboratory and small-scale field trials, extracting sodium carbonate, sodium bicarbonate and sodium chloride from produced waters (Khan & Kordek, 2014, p. 41). However, Penrice's Consortium with GE Power & Water was disbanded during 2013 (Hannam, 2013).

Three Queensland CSG industry proponents collaborated on a Pre-FEED and FEED investigation to inform a feasibility assessment of SSR (Australian Petroleum Production and Exploration Association, 2018, p. 49). The industry spent approximately $60 million on the evaluation of this option.

In December 2018 the Australian Petroleum Production and Exploration Association (APPEA) (2018), the industry body representing Australia's oil and gas explorers and producers, published a report on waste water issues related to the Queensland CSG industry. This report determined SSR was infeasible due to a lack of suitable technology at a commercial scale, high upfront and lifecycle costs, significant energy consumption requirements and low excess demand in the current market (Department of Environment and Science, 2021, p. 1). The APPEA (2018, p. 52) report concluded:

> *The SSR technology cannot at this stage be implemented in a way which appropriately manages the risks of this new technology. Technology providers engaged in the process would not provide assurances that the SSR facility will create a product that is saleable in the market, or indeed that the technology can be successfully deployed. The issue of storing large volumes of residual salts would consequently re-emerge. Investment of ~$800 million into this world first technology is therefore considered infeasible.*

The construction of a baking soda factory at the N2IP is entirely dependent on the NGP proceeding. However, even if the NGP were to proceed, it is uncertain that a baking soda factory would prove to be commercially viable and proceed in any event. Processing salt waste from the CSG industry has previously been considered, trialled and failed as a commercial proposition.

9. Electricity Generated from NGP Gas

9.1 Existing Wilga Park Power Station

As part of the NGP, Santos operates the Wilga Park Power Station that is located to the west of Narrabri. It was originally constructed and operated pursuant to a development consent granted by

Narrabri Shire Council on 14 November 2002 and subsequent modifications (Santos NSW (Eastern) Pty Ltd, 2021).

The Wilga Park Power Station is supplied with gas from CSG fields at Bibbiwindi and Bohena through 32 km buried gas flow line between the CSG fields and the power station (Santos NSW (Eastern) Pty Ltd, 2021). It currently has a maximum capacity of 22 megawatts (MW) although Santos has planning approval to expand the output of the power station up to 40 MW (Santos NSW (Eastern) Pty Ltd, 2021).

Within the National Electricity Market (NEM), the Wilga Park Power Station is categorised as a non-scheduled generator, which applies to generators that generally have an aggregate capacity of between 5–30 MW and do not participate in the central dispatch process. It is understood that the Wilga Park Power Station operates as a non-market generator within the NEM, whereby instead of being paid the spot price applicable at their network connection for each trading interval during which they supply electricity to the market, they sell their entire output to either a local retailer or a customer located at the same connection point on the distribution network.

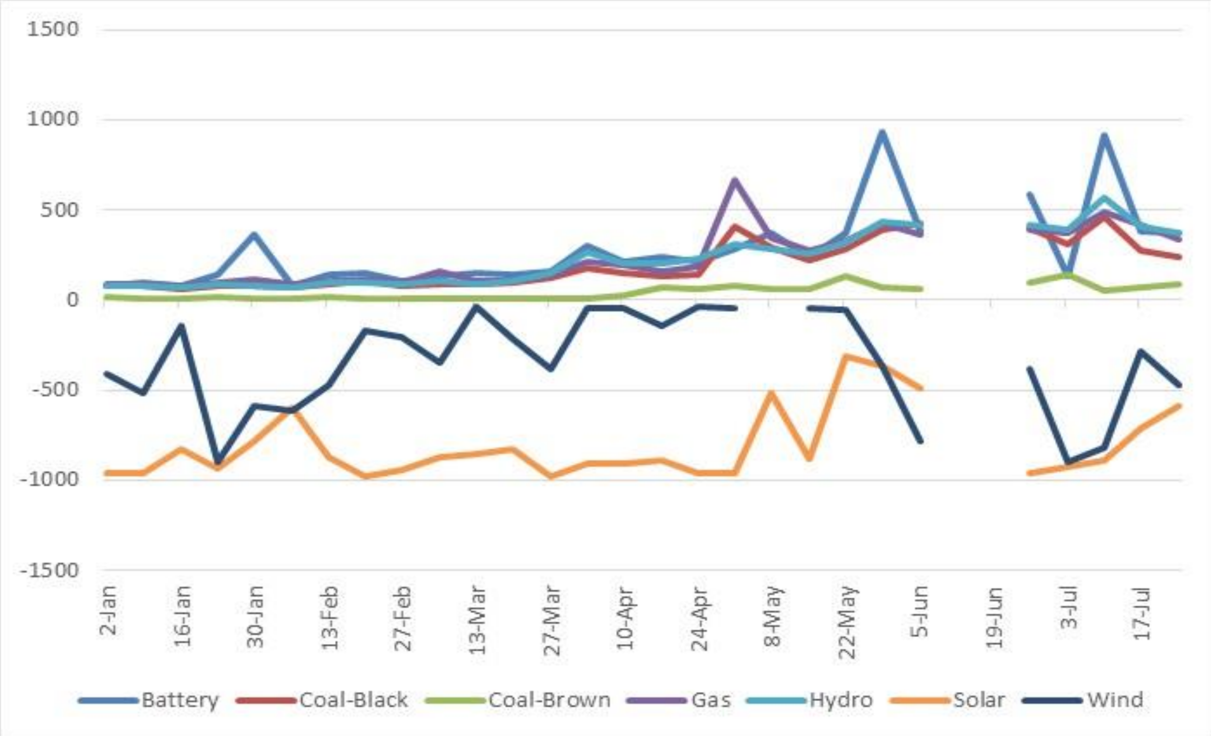
The Wilga Park Power Station operates several small unit open cycle gas turbines that burn gas to heat compressed air that is then released into a turbine to drive a generator.

According to Australian Energy Regulator (2022a, p. 38), gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as ‘flexible’ or ‘peaking’ plant. Across the NEM, gas-powered plants supplied only 8.4% of all electricity generated during 2021 (Department of Industry, Science, Energy and Resources, 2022). In NSW, this was only 2.8% during 2021.

The Australian Energy Regulator (2022b, p. 21) has observed that in recent quarters, gas-powered generation has been required less to meet electricity demand due to an increase in lower cost renewable generation displacing gas. However, the Australian Energy Regulator (2022b, p. 22) noted this trend reversed in the June quarter 2022 due to a reduction in availability of coal fired electricity generation and low renewables generation.

Gas is generally one of the more expensive sources of electricity generation in the NEM, as outlined in Figure 14 below.

*Figure 14: Weekly Average Price for Electricity by Source for NSW – January to June 2022 per Megawatt Hour**



Source: Australian Energy Regulator (2022b).
* Note Administered Price Caps on prices (limiting prices to $300/MWh) were imposed from 15 to 24 June 2022.

9.2 Additional Electricity Generation from NGP Gas

Santos Chairman Keith Spence told the Santos annual general meeting in early May 2022 the NGP still had a market for its gas even if its tentative GSA with Perdaman fell through (Milne, 2022). According to Mr Spence:

> *Perdaman is not the only option for Narrabri, there's options such as power generation and there's the option of exporting the gas.*

With GPG already providing some of the most expensive electricity in the NEM, prospective electricity customers would probably be reluctant to enter into supply contracts with any electricity generators largely dependent upon gas from the NGP.

10. Conclusions

If the current challenging environment in relation to global energy markets were to persist, the NGP is far more likely to proceed in the medium term than PKET. However, with domestic gas prices at record highs in the Eastern Gas Region, major prospective gas customers will be unlikely to rush into signing new GSAs for gas from the NGP any time soon.

New natural gas projects such as the NGP run the risk of becoming stranded due to regulatory requirements that constrain carbon dioxide emissions as well as improvements in alternative energy technology.

So far, Santos has entered into tentative supply arrangements with three potential manufacturers who may also participate in the N2IP. However, developing the N2IP and a Special Activation Precinct predicated on natural gas supply from the NGP exposes participants dependent upon gas to the heightened risk of having their assets stranded as well.

A combination of excess capacity on the east coast of Australia and declining demand for ammonium nitrate explosives in the Sydney and Gunnedah basins, high barriers to entry in relation to substantial sunk costs, and the need to lock in long term supply contracts makes the Perdaman proposal an extremely high-risk commercial proposition. The Perdaman proposal appears to be so fantastic that it is bordering on a hoax. Perdaman could pursue its ammonium nitrate facility by producing green ammonium that employs renewable, rather than fossil fuel sourced hydrogen at Narrabri, although the availability of water could be a limiting factor.

In the current environment with soaring gas prices, it is unlikely that Brickworks would be rushing to sign a GSA for NGP gas any time soon. On the other hand, Brickworks is already investigating using sawdust and methane gas from landfills in its firing of bricks and it is entirely possible that a new Brickworks brick factory could operate at N2IP in the absence of the NGP providing it has access to alternative fuel sources.

The construction of a baking soda factory at the N2IP is entirely dependent on the NGP proceeding. However, even if the NGP were to proceed, it is uncertain that a baking soda factory would prove to be commercially viable and proceed in any event. Processing salt waste from the CSG industry has previously been tried and failed as a commercial proposition.

With GPG already providing some of the most expensive electricity in the NEM, prospective electricity customers would probably be reluctant to enter into supply contracts with any electricity generators largely dependent upon gas from the NGP.

Appendix 1 Natural Gas

Natural Gas Deposits

Natural gas and crude oil are mostly composed of hydrocarbons – compounds of hydrogen and carbon – which have formed from organic matter in the Earth's crust (Huddlestone-Holmes, et al., 2018, p. 29). Natural gas is made up of lighter hydrocarbon compounds that are in a gaseous form. Crude oil has heavier hydrocarbon compounds and form a liquid. There are some hydrocarbons, which have compound sizes between gas and oil called condensates. These compounds are a gas at the temperature and pressure conditions found underground and condense to a liquid when at surface temperatures.

Natural gas contains methane and heavier hydrocarbon compounds (principally ethane, propane and butane) and condensates (Huddlestone-Holmes, et al., 2018, p. 29). The heavier hydrocarbon gasses, once separated from the rest of the gas, are collectively called natural gas liquids (NGLs). Methane is a colourless, odourless and non-toxic gas (CSIRO, 2017).

A basin is a geological formation creating a depression, or dip, in the Earth's surface (National Geographic, 2011). Basins are shaped like bowls, with sides higher than the bottom and structural basins are formed by tectonic activity. Tectonic activity is caused by the movement of large pieces of the Earth's crust, called tectonic plates. The natural processes of weathering and erosion also contribute to forming structural basins. Structural basins form as tectonic plates shift. Rocks and other material on the floor of the basin are forced downward, while material on the sides of the basin are pushed up.

Sedimentary basins are a type of structural basin sometimes forming long troughs (National Geographic, 2011). Over millions of years, the remains of plants and animals build up in thick layers on the earth's surface and ocean floors, sometimes mixing with sand, silt, and calcium carbonate (U.S. Energy Information Administration, 2022). These layers are buried under sand, silt, and rock, and with subsequent pressure and heat changes this carbon and hydrogen-rich material is converted into coal, crude oil, or natural gas.

Petroleum reservoirs, both oil and gas, are the result of sedimentary processes that happened over an extensive geological history (Wang & Economides, 2009, p. 1). Petroleum reservoirs are normally found in sedimentary rocks (Fanchi, 2010). Several key ingredients must be present for a hydrocarbon reservoir to develop. First, a source rock for the hydrocarbon must be present. It is commonly thought that hydrocarbons form from the remains of aquatic life. The remains accumulate in a sedimentary environment such as shale that becomes a source rock. Second, the pressure and temperature of the source rock should be suitable for the generation of oil or gas from the organic mixture.

Conventional gas is trapped reservoirs within in porous and permeable rock such as sandstone or limestone (The South Australian Parliament Natural Resources Committee, 2016, p. 107).[14] It is commonly found in between 400 – 1,000 metres below the ground level, trapped by an overlying impermeable rock formation (South Australian Chamber of Mines and Energy, 2015, p. 4). The gas migrates from very deep gas-rich shales into reservoirs over millions of years.

Unconventional gas is found in source rocks such as coal and shale where the gas has been trapped in place (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 4). With unconventional gas, the source rocks that hold the gas have much lower porosity (that is, the void spaces between the grains that make up the rock are very small) and much lower permeability (that is, the interconnectedness of the pore spaces to allow the gas to move through the rock is very low). Unconventional gas is created through more complex

[14] Porosity is a measure of the void spaces within a rock, while permeability is a measure of the ability of a rock to transmit fluids.

geological formations which limit the ability of gas to easily migrate and therefore more complex extraction methods are required as compared to conventional gas deposits (NSW Environment Protection Authority, 2015, p. 1).

Unconventional gas is known by different names including shale gas, tight gas or coal seam gas (CSG), depending on its situation underground (The South Australian Parliament Natural Resources Committee, 2016, p. 107). CSG does not migrate from shale, but is generated during the transformation of organic material to coal (South Australian Chamber of Mines and Energy, 2015, p. 4). Gas is naturally trapped within the coal by the pressure from water and absorption onto the coals carbon molecules. CSG is usually found at depths of no more than 1,000 metres deep (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 4). Gas in coals located at depths usually below 2,000 metres are often described as deep coal gas (Hall, et al., 2018, p. 21).

Natural Gas Production

Production wells used to extract gas are drilled through the earth directly into gas deposits contained in underground formations (Kegler Brown Hill + Ritter, 2014). Natural gas wells can be drilled vertically as well as horizontally into natural gas-bearing formations (U.S. Energy Information Administration, 2022).

Horizontal drilling involves the production well changing from a vertical to a horizontal direction underground (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 6).

Conventional gas can typically be developed with a limited number of strategically placed wells due to the accumulation of the hydrocarbons in a confined area with well-connected pore spaces within the source rock enabling effective drainage (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 4). With conventional natural gas deposits, the gas generally flows easily up through vertical production wells to the surface (U.S. Energy Information Administration, 2022). In this case gas is generated through, and partly expelled due to, various physical and chemical processes in an organic-rich source rock (Huddlestone-Holmes, et al., 2018, p. 27). The expelled gas migrates upwards through the sediment mass as a result of natural forces such as buoyancy.

With conventional gas deposits, horizontal wells may significantly improve performance if the reservoir is naturally fractured, is thin, or has important gravity features such as a gas-oil or water-hydrocarbon contact (Ahmed, Meehan, & Hughes, 2016, p. 3.1). If there is not sufficient pressure to force the gas into a well at a commercially viable rate, then hydraulic fracture stimulation (fracking) may be used to speed up the flow (The South Australian Parliament Natural Resources Committee, 2016, p. 107).

Fracking refers to the injection of fluid (comprising approximately 99.5% water and proppant (sand) and approximately 0.5% chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 7). This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface. However, conventional wells do not require large scale fracking (Ahmed, Meehan, & Hughes, 2016, p. 3.1).

The additives used in fracturing fluids, whilst generically similar in their combination, differ between companies and are based on site conditions of the specific resource, local geology and company experience, and which chemicals are approved for use in the relevant jurisdiction (Huddlestone-Holmes, et al., 2018, p. 124). Some companies in other jurisdictions have been reluctant to reveal all aspects of their formulae which in turn has fed public distrust. Thus, many jurisdictions have taken steps to either partially or fully require disclosure to regulatory agencies to ensure appropriate controls are in place.

Unconventional hydrocarbon sources were ignored for several decades, largely because of a lack of technology to allow them to be extracted economically (Huddlestone-Holmes, et al., 2018, p. 28).

CSG is typically extracted from coal seams at depths of 300-1,000 metres (CSIRO, 2019). To extract CSG, a steel-encased well is drilled vertically into the coal seam at which point the well may also be fracked or drilled horizontally along the coal seam to increase access to the gas reserves (NSW Environment Protection Authority, 2015, p. 2). Around 10 to 40% of CSG wells in Australia need to be fracked (Frogtech , 2013, p. 2). While the extraction of CSG does not always require fracking, it does require the removal of water from the coal to unlock the gas (dewatering) (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 5). In turn, large amounts of water with salt and sometimes other contaminants are produced in this process and must be treated before disposal.

While the application of horizontal drilling and fracking has dramatically increased natural gas and oil production from unconventional sources in the United States and created opportunities for similar developments in other countries such as Australia, it has also exacerbated global concerns about potential adverse impacts to water, air, and other resources, which are the subject of proliferating research and regulatory attention (Neslin, 2013).

In Australia, unconventional gas, in particular CSG, has been subject to much public criticism which has focused on issues such as the environmental impacts of extraction and the legal rights of landholders whose properties are subject to CSG exploration or production (Select Committee on the Supply and Cost of Gas and Liquid Fuels in New South Wales, 2015, p. 3). This is due to concerns about the impact it may have on water resources and public health, along with the potential for wells and associated infrastructure to impact upon farmland and rural communities.

Over the past decade several State and Territory governments banned various forms of onshore gas exploration and production (Wood & Dundas, 2020, p. 14). Generally, these bans were motivated by concerns about the environmental effects of unconventional gas production, particularly fracking, but also the effects that these activities have on rural landholders.

On 21 July 2011 the New South Wales (NSW) Government announced a moratorium on fracking until 31 December 2011 (Hartcher, 2011a). An NSW Government review of CSG and associated restrictions on gas development led to a new regulatory framework being established in 2014 (Wood & Dundas, 2020, p. 14).

In September 2016 the Northern Territory (NT) Government announced a moratorium on fracking of onshore unconventional shale reservoirs in the NT coupled with a scientific inquiry on the matter (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 3). However, after considering the Inquiry findings, the NT Government (2022). accepted the Inquiry's recommendations and lifted the moratorium on unconventional shale gas developments in the NT in April 2018

Following a similar path set by the NT, the Western Australian (WA) Government announced a ban on fracking for existing and future petroleum titles in the South-West, Peel and Perth metropolitan regions of Western Australia with the future of fracking to be decided following an independent scientific inquiry (Dawson & Johnston, 2017). In late November 2018 the WA Government announced strict new controls over fracking and would only lift the ban on existing onshore petroleum titles following an independent scientific inquiry finding the risk to people and the environment is low (McGowan, Johnston, & Dawson, 2018). The WA Government announced the lifting of the ban on fracking on petroleum titles in September 2019 (Johnston, 2019).

The Victorian Government banned fracking in 2017 and in 2021 enshrined a ban on fracking in the Victorian Constitution (Symes, 2021).

Fracking has also been banned in several European Union countries including France, Germany and Spain (BBC News, 2022).

Applications of Natural Gas and the Domestic Supply Chain

Once the gas is extracted from the wellhead, it is sent to processing plants (U.S. Energy Information Administration, 2022). Natural gas processing involves separation of the various hydrocarbons, fluids and other contaminants from the natural gas (Naturalgas.org, 2013), including NGLs. Non-hydrocarbon gases are removed through processing to reduce impurities and to raise the hydrocarbon content of pipeline-quality natural gas (Bradbury, Clement, & Down, 2015, p. 8). These non-hydrocarbon gases are typically vented into the atmosphere.

The NGLs can be very valuable by-products of natural gas processing (Naturalgas.org, 2013), and can be used as inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel (U.S. Energy Information Administration, 2012). Ethane occupies the largest share of NGL field production and is used almost exclusively to produce ethylene, which is then turned into plastic. Blends of propane and butane are more commonly known as liquid petroleum gas (LPG).

Natural gas plays a very important role in our society as a raw material for a great variety of industrial processes (Abánades, 2018). Its utilisation as a primary energy source has been consolidated during the past few decades due its high hydrogen/carbon ratio, efficient combustion, and lower amounts of contaminants in the exhausted gases, including lower carbon dioxide emissions than coal when used for electricity generation.

Natural gas has a wide range of applications including as a feedstock for gas powered generators (GPG) for electricity production, and as a power source for appliances such as gas heaters, gas water heaters and gas stoves. Natural gas is widely viewed as a transitional fuel to a lower carbon economy because of its much lower greenhouse gas emissions per unit of electricity produced compared to coal (Day, Connell, Etheridge, Norgate, & Sherwood, 2012, p. iii). Rapid changes in electricity generation power output from variable renewable energy generation need to be balanced with generation technology that has the ability to increase (ramp up) or decrease (ramp down) power output at the same time and gas-fired generators have the ability to 'fast ramp' (Finkel, Moses, Munro, Effeney, & O'Kane, 2017, p. 107).

The manufacturing sector is the largest consumer of gas and comprises a few large consumers, including metal product industries (mainly smelting and refining activities), the chemical industry (fertilisers, explosives and plastics) and the cement industry (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 101). Natural gas is also an important input in many industrial processes, including the production of pulp and paper, stone, clay, glass and processed foods (Australian Energy Regulator, 2018, p. 183).

Gas producers sell wholesale gas domestically to electricity generators, to other large gas users and to energy retailers, who then on-sell the gas to businesses and household customers (Australian Competition and Consumer Commission, 2018b, p. 5). The gas produced for domestic consumption is transported ('shipped') through high pressure transmission pipelines from the production facility to the entry point of the distribution network ('city gate') or to large users (for example, large commercial and industrial users) connected to the transmission pipeline.

Gas distribution pipelines transport natural gas from transmission pipelines to end users (Australian Competition and Consumer Commission, 2018b, p. 5). These typically consist of a backbone of high and medium pressure pipelines running between the city gate and major demand centres. This pipeline system feeds low pressure pipelines which deliver the gas to businesses and homes. Energy retailers act as intermediaries by buying gas from producers and packaging it with pipeline services for sale to residential, commercial and small business customers.

Natural Gas Exports

International trade in natural gas occurs through two modes of transport – pipelines and sea freight. Where natural gas pipelines are not feasible or do not exist, liquefying natural gas is a way to move natural gas from producing regions to markets (U.S. Energy Information Administration, 2019). Natural gas liquefies at minus 161.5 degrees Celsius, at which temperature it reduces to 1/630 times its original volume (Stopford, 2009, p. 606).

A liquefaction plant has one or more 'trains' which liquefy the gas (Stopford, 2009, p. 486). A train is a compressor, usually driven by a gas turbine, which compresses a coolant until it reaches minus 163 degrees Celsius, at which temperature the gas is reduced in volume and feeds into cooling coils which liquefy the gas passing over them. This liquid natural gas (LNG) is stored in refrigerated tanks until a ship arrives and transports it to its destination.

At its destination, a regasification plant at an import terminal turns the LNG back into natural gas, and feeds it into a power utility or the local pipeline system (Stopford, 2009, p. 487).

During 2021, 44 countries imported LNG with Asia accounting for 73.2% of global LNG imports (International Group of Liquefied Natural Gas Importers, 2022). The five largest importers of LNG, in China, Japan, South Korea, India, and Taiwan account for just around 65.3% of global LNG imports. In 2021 China overtook Japan for the first time as the world's top LNG importing country.

In 2021 Australia was the largest exporter of LNG, accounting for 21.1% of global exports, closely followed by Qatar accounting for 20.7%, and the United States accounting for 18% (International Group of Liquefied Natural Gas Importers, 2022).

Appendix 2 Ammonia as a Hydrogen Carrier

As a potential hydrogen carrier, ammonia is projected to be a sustainable fuel with high hydrogen content in the near future (Bicer, Dincer, Vezina, & Raso, 2017). Expectations are rising for hydrogen and hydrogen carriers as a medium for storage and transportation of energy in the mass introduction and use of renewable energy. Storage and transport of hydrogen is an important issue since hydrogen is a gas under normal temperature and pressure. Hydrogen carriers are mediums that convert hydrogen into chemical substances containing large amounts of hydrogen, to simplify storage and transport processes. Hydrogen carriers include ammonia synthesised from nitrogen and hydrogen that can be used for direct combustion.

The energy storage properties of ammonia are fundamentally similar to those of methane (The Royal Society, 2020, p. 7). Methane has four carbon-hydrogen bonds that can be broken to release energy and ammonia has three nitrogen-hydrogen bonds that can be broken to release energy. The crucial difference is the central atom, where, when burnt, the carbon atom in methane produces carbon dioxide, whereas the nitrogen atom in ammonia results in nitrogen gas, N_2.

To store ammonia in bulk, it requires liquefaction either by compression to 10 times atmospheric pressure or chilling to -33°C (The Royal Society, 2020, p. 7). Hydrogen by comparison is also a gas at atmospheric pressure and room temperature. However, to store hydrogen at scale it must be compressed to around 350 to 700 times atmospheric pressure, or cryogenically cooled to -253°C. Consequently, the storage of hydrogen is more difficult, energy intensive and expensive than storing ammonia.

Ammonia is a suitable fuel for transport modes where large amounts of energy are required for extended periods of time and where batteries or direct electrical connection are not practical or cost effective (The Royal Society, 2020, p. 31). Examples include heavy good vehicles, trains, aviation and shipping. Indeed, ammonia has previously been used as a transport fuel for buses in Belgium in the 1940s (MacFarlane, et al., 2020, p. 1187). Internal combustion engines (ICE) can also be converted to run on ammonia, (MacFarlane, et al., 2020, p. 1197). Application of ammonia as a marine fuel is noticeably attracting attention of the shipping industry, as a response to recent mandates by the International Maritime Organization regarding lowering of sulfur content of fuels and also for the ultimate decarbonisation of shipping by 2050 (MacFarlane, et al., 2020, p. 1198).

For a host of remote-community and off-grid situations diesel generators are currently the power source of choice, supplemented by solar and wind, and often at high fuel costs given the delivery distance (MacFarlane, et al., 2020, p. 1198). In this setting, small to medium scale generators running on ammonia that is produced and stored locally becomes a competitive concept.

Co-firing with low-carbon fuels is a complementary approach for decarbonising existing fossil fuel power plants (International Energy Agency, 2022, p. 23). The use of ammonia as a supplementary fuel in coal- and gas-fired power generators has been demonstrated in Japan. This would assist in transitioning such facilities toward lower carbon emissions as soon as sufficient quantities of ammonia become available at competitive prices (MacFarlane, et al., 2020, p. 1198). Ultimately, this particular application could lead to ammonia being used for large-scale renewable energy storage and power generation at the grid level.

Modifying existing coal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporisers (International Energy Agency, 2022, p. 23). In addition, gas turbine manufacturers have announced plans to offer large-scale ammonia-fired gas turbines around 2025. Ammonia-fired systems benefit from the easier storing of ammonia relative to hydrogen, but the use of NH_3 as fuel poses additional technical challenges arising from its toxic and corrosive nature (International Energy Agency, 2022, p. 28).

According to Prakash Sharma, Flor De la Cruz and Jonathan Sultoon from energy consultants Wood Mackenzie (2022, p. S70):

> *Ammonia is emerging as a key technology option for the energy transition. Its versatility in power, mobility and industrial applications, preference to carry hydrogen at low cost and the ability to quickly scale up supplies leveraging existing infrastructure are clear benefits, and investors are taking note.*

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