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Unconventional Gas in the Lake Eyre Basin

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

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Key Points

The costs of producing unconventional gas from the Cooper Basin will be high

- In relative terms, the development of 2C contingent resources in the Cooper Basin, ranks 13 out of 17 actual and undeveloped gas projects in terms of production costs, according to Australian Energy Market Operator (AEMO) (2022c).
- The delivery cost of 2C contingent resources from the Cooper Basin to the Wallumbilla Hub generally exceeds the forecast Wallumbilla Hub wholesale price forecasts prices as published in the 2022 *Gas Statement of Opportunities* (GSOO) by the AEMO (2022) under all scenarios.

Increased pressure to offset emissions will increase costs further

- While other gas fields may also have to deal the cost of offsetting fugitive emissions, the high CO_2 content of unconventional gas from the Cooper Basin (around 30%) puts it at a distinct competitive disadvantage compared to other gas fields where the CO_2 content of the raw gas is much lower.
- The estimated cost of offsetting 4.1 Mt of CO_2-e annually from fugitive emissions under a low export gas scenario for the production of unconventional gas in the Cooper Basin based on the current price of Australian Carbon Credit Units (ACCUs) would be $145.2 million per annum, adding $0.36 per GJ to the cost of gas.
- The cost of offsetting 3.9 Mt of CO_2 emissions annually from venting during processing would be $136.5 million, adding $0.34 per GJ to the cost of gas.
- The total cost of offsetting fugitive emissions and emissions from venting during processing of 8.0 Mt of CO_2-e would be $281.6 million per annum, adding $0.70 per GJ to the cost of gas.

Carbon capture and storage has proven to be an unreliable technology that has not succeeded at scale in Australia

- While carbon capture and storage (CCS) technology has been in operation for half a century, it has proven to be an unreliable technology in several cases (Robertson & Mousavian, 2022, p. 1). The majority of projects globally using CCS have had unique engineering challenges that have led to underperformance and cost blow-outs.
- The Gorgon Gas Project, located on Barrow Island around 60 km off the northwest coast of Western Australia and operated by Chevron, is one of the world's largest LNG projects (Chevron Australia, 2022), and had plans to inject 3.3 to 4 Mt of CO_2 per year.
- However, it has been beset by serious problems. It did not start injection until three years later then intended, and as of May 2022 it is operating at only half of its designed capacity.

Global push towards Net Zero Emissions by 2050 will preference lowest cost and lowest emissions producers

- In its roadmap for the global energy sector to reach Net-Zero Emissions by 2050, the International Energy Agency (IEA) (2021, p. 175) has suggested that nearly all liquid natural gas (LNG) exports in 2050 will come from the lowest cost and lowest emissions producers.
- Production costs of unconventional gas in Australia are likely to be significantly higher than those in North America and the lack of infrastructure will further add to costs (Cook, et al., 2013).
- The available evidence suggests unconventional gas produced from the Cooper Basin in the Lake Eyre Basin will be neither low cost nor low emissions.
- Any requirement to offset emissions from the production of unconventional gas from the Cooper Basin in the Lake Eyre Basin will further erode its competitiveness given the high CO_2 content of raw gas.

- Rather than pose the risk of becoming stranded assets, the commercial production of unconventional gas from the Lake Eyre Basin would be the absolute height of folly if it were ever to be commenced.

Increase Supply will put downward pressure on global gas prices

- While the global LNG market is expected to be tight through to 2025, as demand growth is evenly matched by supply growth, from 2026 onwards several sizeable projects are expected to come online in both the U.S. and Qatar which is expected to result in the market being over-supplied (Department of Industry, Science, Energy and Resources, 2022, p. 79), in turn putting downward pressure of global LNG prices.

Executive Summary

Introduction

- Lock the Gate has commissioned Pegasus Economics (Pegasus) to undertake an analysis of the likely costs of developing unconventional gas in the Queensland portion of the Lake Eyre Basin, within the context of the projected global trajectory of gas markets and accelerating action on climate change.

Natural Gas

- Natural gas contains methane and heavier hydrocarbon compounds (principally ethane, propane and butane) and condensates (Huddlestone-Holmes, et al., 2018, p. 29).
- Petroleum reservoirs, both oil and gas, are the result of sedimentary processes that happen over an extensive geological history (Wang & Economides, 2009, p. 1). Petroleum reservoirs are normally found in sedimentary rocks (Fanchi, 2010).
- Conventional gas is trapped in porous and permeable rock such as sandstone or limestone (The South Australian Parliament Natural Resources Committee, 2016, p. 107). 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).
- 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).
- 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 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).
- Tight gas generally occurs at depths between 2,000–5,000 metres (The South Australian Parliament Natural Resources Committee, 2016, p. 110).
- Basin-centred gas consist of gas trapped outside the limits of conventional structural traps, potentially forming an extensive accumulation in the deeper parts of the basin (Proactive, 2014). The reservoir sandstones holding this gas are typically of lower reservoir quality, referred to as tight gas sands.
- Shale gas usually occurs at similar depths to tight gas (Hall, et al., 2018, p. 21).
- Production wells used to extract gas from subsurface deposits 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 and horizontally into natural gas-bearing formations (U.S. Energy Information Administration, 2022).
- 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 (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 4).
    - With conventional natural gas deposits, the natural gas generally flows easily up through vertical production wells to the surface (U.S. Energy Information Administration, 2022).
- Hydraulic fracture stimulation (fracking) refers to the injection of fluid (comprising approximately 99.5 per cent water and proppant (sand) and approximately 0.5 per cent 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.

- Before gas can be extracted from the shale gas reservoir, fracking must be undertaken (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 6).
- In general, a vertical well drilled and completed in a tight gas reservoir must be successfully stimulated through fracking to produce at commercial gas-flow rates and produce commercial gas volumes (Holditch, 2006).
- Once the gas is extracted from the wellhead, it is sent to processing plants (U.S. Energy Information Administration, 2022). Non-hydrocarbon gases that are part of the raw natural gas are removed through processing to reduce impurities and to raise the hydrocarbon content of the pipeline-quality natural gas (Bradbury, Clement, & Down, 2015, p. 8). Non-hydrocarbon gases removed during processing are typically vented into the atmosphere.
- 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).
- 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.

Lake Eyre Basin and Underlying Basins

- The Lake Eyre Basin (LEB) is a shallow endorheic (hydrologically landlocked) basin extending across the Northern Territory (NT), South Australia (SA), New South Wales (NSW), and Queensland (Wakelin-King, 2022, p. 113). It covers nearly one sixth of the Australian continent and is one of the largest internally draining river basins in the world (Fielder, Grady, & Broadbent, 2019, p. vi).
- In terms of the existence of as yet undeveloped unconventional gas resources within the LEB, they are most likely to be found within the Cooper Basin along with the overlying Eromanga Basin and the Georgina Basin which are geological basins within the broader LEB.
- An independent scientific panel commissioned by the Queensland Government recommended in relation to the LEB that:

  Infrastructure for mining and petroleum/gas activities should not be allowed in the floodplains because of flow alterations, fish passage issues and major impacts to floodplain ecosystems. (Fielder, Grady, & Broadbent, 2019, p. 25)

  Unconventional petroleum and gas production be an unacceptable use in the Designated Precinct (DP) (Fielder, Grady, & Broadbent, 2019, p. 41).

Cooper-Eromanga Basins

- The Eromanga Basin is a sedimentary basin encompassing an area of approximately 1 million km^2 in central Australia (Wecker, 1989, p. 379).
- The Cooper Basin is a sedimentary basin that covers an area of around 130 000 km^2 (Robinson, et al., 2019, p. 947).
  - The overlying Eromanga Basin covers the entire lateral extent of the Cooper Basin.
  - The Eromanga and Lake Eyre basins contain the extensive groundwater system of the Great Artesian Basin.
- 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 is considered highly prospective for unconventional gas including tight and deep coal gas resources, and has medium relative prospectivity for shale gas (Lech, et al., 2020, p. 163).
- Given the Cooper Basin's existing conventional production and proximity to gas processing and pipeline infrastructure, the industry is currently investigating opportunities in tight, shale and deep coal plays in the basin (Robinson, et al., 2019, p. 947).
- Substantial gas infrastructure, including a gas pipeline servicing SA, Queensland and NSW markets, already exists in the Cooper Basin (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 118).

Georgina Basin

- The Georgina Basin is a sedimentary basin that covers an area of around 330 000 km^2 in the central-eastern Northern Territory that extends into western Queensland (Kruse, Dunster, & Munson, 2011, p. 28.1).
- The southern part of the Georgina Basin is considered to be among the most prospective onshore areas for oil and gas potential and to have world-class shale source rocks (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018, p. 93).

Eastern Gas Region

- 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).
- 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).
- Starting in the late 1990's, CSG from Queensland began to enter the Eastern Gas Region (Forcey & McConnell, 2017, p. 10).
- 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).
- Located in the Eastern Gas Region at Curtis Island near Gladstone in Queensland are now three liquid natural gas (LNG) export projects.
- While most of the Eastern Gas Region's reserves are 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).
- Consumption of natural gas from the LNG export projects now dwarfs that for domestic users (Bethune & Wilkinson, 2019, p. 520).
  - In 2021 LNG exports accounted for around 71.8 per cent of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2022).

Reserve and Resource Estimates

- 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 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 per cent probability (P50) that the quantities actually recovered will equal or exceed the best estimate (Society of Petroleum Engineers, 2018, p. 12).
- 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.
- The majority of 2P reserves in the Eastern Gas Region are located in CSG fields in Queensland, with 70 per cent of 2P reserves located in the Surat Basin and 18 per cent in the Bowen Basin (Australian Competition and Consumer Commission, 2022, p. 162).
- The remaining 2P reserves are located in offshore Victoria (8 per cent), the Cooper Basin (3 per cent), the Amadeus Basin (0.7 per cent), the Gunnedah Basin (0.05 per cent) and the Sydney Basin (0.007 per cent).
- Like 2P reserves, the majority of 2C resources are located in Queensland (Australian Competition and Consumer Commission, 2022, p. 163).
- While CSG accounts for the majority of the 2C resources (64 per cent), other unconventional sources of gas (19 per cent) (e.g. tight gas and shale gas) located primarily in the Bowen, McArthur and Cooper basins, are starting to account for an increasing proportion of 2C resources over the last three years (Australian Competition and Consumer Commission, 2022, p. 163).
- Gas producers can face a range of technical challenges when developing CSG and other unconventional gas fields, therefore a significant degree of uncertainty surrounds whether these contingent resources will be commercially recoverable in the future (Australian Competition and Consumer Commission, 2022, p. 163).
- Despite unconventional targets for shale gas being recognised across many Australian sedimentary basins, there have been no definitive tests that prove that any of these potential plays will flow gas at commercial rates (Close, 2015).
- The best estimate of contingent resources of unconventional gas resources available in the Cooper Basin by gas producers and prospecting companies based on research by Pegasus is around 5 trillion cubic feet (Tcf).
- The U.S. Geological Survey (USGS) (2016) has also estimated contingent resources of tight gas of 25.74 Tcf and deep coal gas of 0.26 Tcf in the Cooper Basin.
- There are also very large estimates of potentially recoverable prospective unconventional gas resources in the Cooper Basin (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 98).
- Based on the encouraging desktop studies by the U.S. Energy Information Administration, Chevron, Santos and Beach Energy began an ambitious exploration program for shale gas in the Cooper Basin, however, the results were disappointing (Bethune, 2020).
- The Arthur Creek Formation is considered to contain the most prospective unconventional gas targets in the Georgina Basin (Hall, et al., 2018).
- Around 22 wells have been drilled in the southern Georgina Basin targeting shale oil, shale gas and basin-centred gas plays (Hall, et al., 2018, p. 56). However, drilling results to date have met with mixed success.
- In terms of shale and tight gas prospectivity, the Georgina Basin has been ranked as moderate, reflecting the relatively poor results of recent exploration with a low–moderate confidence reflecting sparse data distribution (Hall, et al., 2018, p. vi).
- According to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018, p. 96) in relation to the Georgina Basin:

There remains a great deal of uncertainty about the ability of the rocks within the basin to generate and host significant volumes of hydrocarbons. In this respect, the Georgina Basin lags behind the Beetaloo Sub-basin, so any discovery made today would almost certainly be more than three years from commercialisation and potentially more than a decade.

Gas Prices and Gas Production Costs for the Eastern Gas Region

- In the opinion of Pegasus, the gas price forecasts prepared for the 2022 *Gas Statement of Opportunities* (GSOO) by the Australian Energy Market Operator (AEMO) (2022), taking account of both the developments in the Eastern Gas Region and global LNG markets, provide the most plausible likely trajectory for both domestic and global markets in relation to gas over the next thirty years out to 2050.
- In relative terms, the development of 2C contingent resources in the Cooper Basin, presumably including the development and production of gas from unconventional reservoirs, ranks 13 out of 17 actual and undeveloped gas projects in terms of production costs.
- There are 12 developed and undeveloped gas projects with lower estimated production costs than the production of unconventional gas in the Cooper Basin. These 12 developed and undeveloped gas projects with estimated lower production costs represent some 53,700 petajoules (PJ) of 2P and 2C natural gas resources.
- Furthermore, while the cost of producing from undeveloped 2C contingent resources in the Bowen and Surat basins appears to be slightly above the cost of undeveloped 2C contingent resources in the Cooper Basin, infrastructure transport costs to deliver gas to the Wallumbilla Hub will be considerably lower, in turn suggesting that undeveloped 2C contingent resources from the Bowen and Surat basins are likely to be developed long before any consideration is given to developing 2C contingent resources from the Cooper Basin.
- The delivery cost of 2C resources from the Cooper Basin to the Wallumbilla Hub generally exceeds the forecast Wallumbilla Hub wholesale price forecasts prices as published in the 2022 GSOO under all scenarios.
- While as part of the 2022 GSOO the AEMO (2022c) estimates production costs for 2C gas resources in the Beetaloo/Georgina Basin, it highly likely that this relates entirely to the development and production of unconventional gas in the Beetaloo Sub-basin.
    - This is because any commercial gas discovery in the Georgina Basin would almost certainly be more than three years from commercialisation and potentially more than a decade according to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018, p. 96).

Carbon Dioxide Emissions From Unconventional Gas Production in the Lake Eyre Basin

Development of Emissions Scenarios

- Professor Ian Lowe (AO) (2022) has estimated the likely emissions from both carbon dioxide (CO_2) and carbon dioxide-equivalent (CO_2-e) in relation to the following scenarios for the production of unconventional gas in the LEB:
    - Emissions for a low export gas scenario (400 PJ per year)
    - Emissions for a high export gas scenario (2,000 PJ per year).
- In the Net-Zero Emissions by 2050 Scenario (NZE) developed by the International Energy Agency (IEA) (2021, p. 175) in its roadmap for the global energy sector, no new oil and natural gas fields are required beyond those already approved for development, and supplies become increasingly concentrated in a small number of low-cost producers.
- On this basis, the development of any new commercial gas fields in the Georgina Basin would arguably put the Queensland Government in breach of its target for net zero emissions by 2050.

- Given the scale of future development required in the Cooper-Eromanga basins under both the high and low export gas scenarios, the Queensland Government's commitment to net zero emissions by 2050 would also become problematic.
- The production of an additional 2,000 PJ per annum of unconventional gas under the high export gas scenario is probably unlikely as it would more than double current gas production in the Eastern Gas Region.
- On this basis, further consideration of a high export scenario has been excluded from the analysis.
- In the further development of a low export scenario, it will be assumed unconventional gas is sourced exclusively from the Cooper-Eromanga basins given the uncertainty surrounding the quantity of unconventional gas resources in the Georgina Basin.

Carbon Dioxide Content of Unconventional Gas in the Cooper Basin

- Unconventional gas in the Cooper Basin have been shown to have a relatively high CO_2 content, ranging from around 21 per cent to almost 36 per cent (Lech, et al., 2020).
- Rounding up a simple average of the CO_2 content from the various unconventional desorbed gas samples from across the Cooper Basin gives an average CO_2 content of 30 per cent.
- The simple average of the methane content from the various unconventional desorbed gas samples from the Cooper Basin gives an average methane content of around 62 per cent.

Fugitive Emissions

- 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 (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 a number of 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).[1]
- 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 per cent of methane was emitted between extraction and delivery across the U.S. natural gas supply chain, including from both conventional and unconventional gas wells.
- Taking a GWP for methane of 29.8 and assuming that fugitive emissions represent 1.7 per cent of total raw gas production for a low export gas scenario provides an estimate of fugitive emissions of 4.1 megatonnes (Mt) of CO_2-e per annum.

Natural Gas Processing Emissions

- 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 removed during processing are typically vented into the atmosphere, which can include venting of CO_2 (Bradbury, Clement, & Down, 2015, p. 8).

[1] See Forster, et al., (2021, p. 1017). While Australia's National Greenhouse Gas Accounts (Department of Industry, Science, Energy and Resources, 2021, p. 65) uses GWP for methane 28 times that of CO_2, this is based on the Fifth Assessment Report (AR5) of the IPCC.

- A low export gas scenario, provides an estimate of CO_2 emissions vented during the processing of natural gas of 3.9 Mt per annum in order to produce 400 PJ of processed natural gas.

Carbon Capture and Storage

- High emissions during the processing stage could be reduced through carbon capture and storage technology (CCS) (Cook, et al., 2013, p. 143).
- CCS takes CO_2 captured from the burning of fossil fuels and other sources, and injects it deep underground into the tiny pore spaces present between grains in sedimentary rocks (such as sandstones) (Geoscience Australia, n.d.).
- On 1 November 2021 Santos (2021) announced that it along with its joint venture partner in the Cooper Basin Beach Energy had taken a final investment decision to proceed with the US$165 million Moomba CCS project in SA, with start-up expected in 2024.
- Santos Managing Director and Chief Executive Officer Kevin Gallagher said the Moomba CCS project will be one of the biggest and lowest cost in the world and will safely and permanently store 1.7 Mt of CO_2 per year.
- On this basis, it is feasible that the venting CO_2 emissions from processing unconventional gas development in the Cooper Basin could be partially offset through CCS.
- While CCS technology has been in operation for half a century, it has proven to be an unreliable technology in several cases (Robertson & Mousavian, 2022, p. 1). The majority of projects globally using CCS have had unique engineering challenges that have led to underperformance and cost blow-outs.
- The Gorgon Gas Project, located on Barrow Island around 60 km off the northwest coast of Western Australia and operated by Chevron, is one of the world's largest LNG projects (Chevron Australia, 2022). As part of the Gorgon Gas Project, the Gorgon carbon dioxide injection project had plans to inject 3.3 to 4 Mt of CO_2 dioxide per year into the Dupuy Formation, a geological layer consisting of sandstone more than two kilometres beneath Barrow Island (Department of Mines, Industry Regulation and Safety, n.d.; Chevron Australia, 2021).
- It was originally intended for the Gorgon carbon dioxide injection project to commence operations in 2016 (Carbon Capture and Sequestration Technologies program at MIT, 2016), however, it didn't commence injecting CO_2 until early August 2019 (Department of Mines, Industry Regulation and Safety, n.d.).
- Chevron Australia's director of operations, Kory Judd, commented in May 2022 the CCS project was operating at only half of its designed capacity and that the company did not have a timeframe for when it would be able to meet its CO_2 capture targets (Newsbase Daily News, 2022).
- Bruce Robertson and Milad Mousavian (2022, p. 11) from the Institute for Energy Economics and Financial Analysis have pondered in relation to the Gorgon carbon dioxide injection project:

  > *The extent of the technical failure of Gorgon CCS cannot be overstated. It prompts the question: if the engineers from the project backers – the super major oil companies Chevron, Shell and Exxon – cannot get CCS to work as forecast, who can?*

- Similarly, Channel 9 newspapers business reporter Peter Milne (2022) has mused:

  > *The conundrum of CCS is that it has a patchy record of performance to date but still features as an essential part of most scenarios to achieve net-zero emissions by 2050.*

Cost of Offsetting Fugitive Emissions and Natural Gas Processing Emissions

- 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). 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.
- As a low export gas scenario for the production of unconventional gas in the Cooper Basin will be emitting around 8.0 Mt of CO_2-e emissions per annum, it will need to be covered by the safeguard mechanism.
- ACCUs were trading around $35.25 a tonne on the spot during June 2022, only slightly above the cost ceiling for CCS at Moomba nominated by Santos (taking into account the prevailing exchange rate). This in turn suggests that the cost of offsetting emissions through the purchase of ACCUs will be roughly equal to the cost of offsetting emissions through CCS.
- The estimated cost of offsetting 4.1 Mt of CO_2-e from fugitive emissions for a low export gas scenario for the production of unconventional gas based on the current price of ACCUs would be $145.2 million per annum, adding $0.36 per GJ to the cost of gas.
- The cost of offsetting 3.9 Mt of CO_2 emissions from venting during processing would be $136.5 million, adding $0.34 per GJ to the cost of gas.
- The total cost of offsetting fugitive emissions and emissions from venting during processing of 8.0 Mt of CO_2-e would be $281.6 million, adding $0.70 per GJ to the cost of gas.
- While other gas fields may also have to deal the cost of offsetting fugitive emissions, the high CO_2 content of unconventional gas from the Cooper Basin puts it at a distinct competitive disadvantage compared to other gas fields where the CO_2 content of the raw gas is much lower.

Conclusions

- In its roadmap for the global energy sector to reach NZE by 2050, the IEA (2021, p. 175) has suggested that nearly all LNG exports in 2050 will come from the lowest cost and lowest emissions producers.
- The available evidence suggests unconventional gas produced from the Cooper Basin in the Lake Eyre Basin will be neither low cost nor low emissions.
- Any requirement to offset emissions from the production of unconventional gas from the Cooper Basin in the Lake Eyre Basin will further erode its competitiveness given the high CO_2 content of raw gas.
- Rather than pose the risk of becoming stranded assets, the commercial production of unconventional gas from the Lake Eyre Basin would be the absolute height of folly if it were ever to be commenced.

1. Introduction

Lock the Gate has commissioned Pegasus Economics (Pegasus) to undertake an analysis of the likely costs of developing unconventional gas in the Queensland portion of the Lake Eyre Basin, within the context of the projected global trajectory of gas markets and accelerating action on climate change. In particular, Lock the Gate sought:

1. Assessment of the likely cost of unconventional gas from the Lake Eyre Basin in Queensland in relation to the global cost curve for unconventional gas developments
2. Assessment of the likely costs of offsetting the emissions estimated by Professor Ian Lowe for developing unconventional gas in the Lake Eyre Basin
3. Review of the Gorgon Gas Project for the likelihood of implementation of carbon capture and storage and assesses likely costs of carbon capture and storage for the emissions estimated by Professor Lowe (noting carbon and capture and storage does not deal with fugitive methane emissions but can apply to vented carbon dioxide and any combustion emissions)
4. Assessment of the likely impacts on gas price of offsetting/capturing emissions from any gas development in the region
5. Describe the likely trajectory of the global markets for gas over the next thirty years to 2050
6. Assessment of the likelihood of gas assets becoming stranded over the next 30 years and describe the risks associated with investment now in that context.

In assessing emissions, Pegasus has been requested to focus on the emissions directly associated with the production of unconventional gas production in the Lake Eyre Basin and to exclude consideration of emissions arising from the burning of gas.

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

2. Natural Gas

2.1 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 gas 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).

Condensates are also a valuable commodity because of their versatile utility as fuels or process chemicals. In addition, raw natural gas contains water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds (Naturalgas.org, 2013).

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).[2] 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 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).

Tight gas accumulations occur in a variety of geologic settings where gas migrates from a source rock into a sandstone formation, but is limited in its ability to migrate upward due to reduced permeability in the sandstone (South Australian Chamber of Mines and Energy, 2015, p. 4). The natural gas is sealed in extremely impermeable, hard rock, making the underground formation extremely 'tight' and difficult to access (Rajput & Thakur, 2016). It generally occurs at depths between 2,000–5,000 metres (The South Australian Parliament Natural Resources Committee, 2016, p. 110).

Basin-centred gas consist of gas trapped outside the limits of conventional structural traps, potentially forming an extensive accumulation in the deeper parts of the basin (Proactive, 2014). The reservoir sandstones holding this gas are typically of lower reservoir quality, referred to as tight gas sands.

[2] 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.

Shales are the most abundant types and volumes of rocks in sedimentary basins worldwide (Ahmed, Meehan, & Hughes, 2016, p. 3.2). Shales are clastics (portions of older rocks) sedimentary rocks composed of silts, muds, and clays. Shale forms on the beds of large bodies of water over very long periods of time (The South Australian Parliament Natural Resources Committee, 2016, p. 109). Layers slowly build up, sometimes in great thicknesses, with organic matter which forms hydrocarbon deposits as it decomposes. If no fracturing (either natural or manmade) occurs, gas and oil can remain trapped in shale indefinitely (Stephenson, 2015, p. 25). Shale gas usually occurs at similar depths to tight gas (Hall, et al., 2018, p. 21).

Shale gas can be either dry gas composed primarily of methane (60–95 per cent volume per volume), or wet gas where methane is accompanied by considerable quantities of heavier gases (compounds such as ethane, propane and butane) (Huddlestone-Holmes, et al., 2018, p. 31).

2.2 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 per cent water and proppant (sand) and approximately 0.5 per cent 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 per cent 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.

Queensland's CSG resources now supply the majority of gas used in the eastern Australian gas market, including gas used for export (Huddlestone-Holmes, et al., 2018, p. 1).

To extract shale gas, wells are drilled anywhere from 1,500 – 4,000 metres deep through several layers of rock to access the shale (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 5). The wells are lined with various steel casings which are cemented using fit-for-purpose cement designed to protect groundwater from contamination. To maximise shale gas recovery, horizontal drilling is required whereby the well changes from a vertical to a horizontal direction deep underground.

Before gas can be extracted from a shale gas reservoir, fracking must be undertaken (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 6). The fracking of shale gas reservoirs only returns a portion of the water that is used in the process (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 4). This returned water (flowback water) can be recycled and re-used for the next hydraulic fracturing operation, or be treated for disposal.

Although the amount of wastewater generated from shale gas will be an order of magnitude less than from CSG, it is likely to be highly saline, and may contain 'geogenic' chemicals such as heavy metals, naturally occurring radioactive materials and organic compounds such as benzene, toluene and xylene (known as BTEX compounds) and other hydrocarbons (Huddlestone-Holmes, et al., 2018, p. 125). During fracking, the fluids mix with formation material at depth, resulting in a large volume of liquid waste containing these substances.

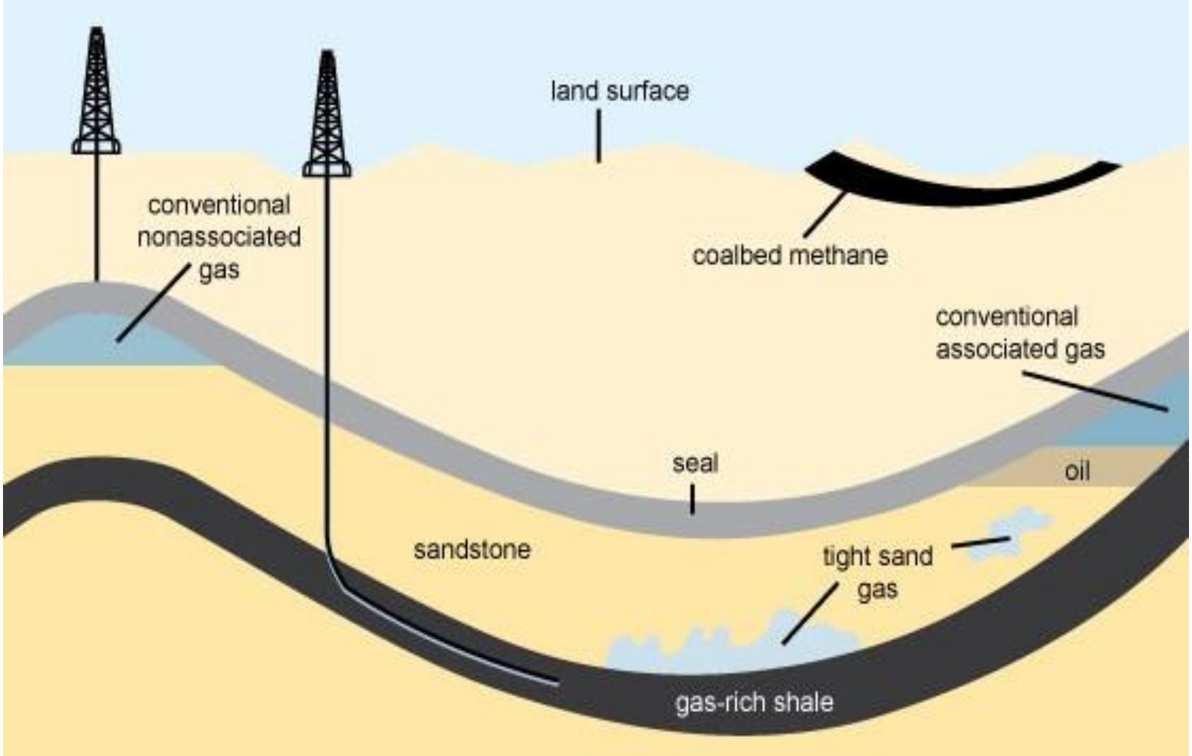
The United States is one of the few countries to have developed shale gas on a commercial scale (Knight & Bell, 2014). The successful development of shale gas and oil in the United States has resulted in worldwide interest in unconventional petroleum resources (Huddlestone-Holmes, et al., 2018, p. 30). In 2012, Santos developed Australia's first commercially producing shale gas well in the Cooper Basin in South Australia (SA), although to date no other Australian state has seen the commercial production from shale gas wells (Huddlestone-Holmes, et al., 2018, p. 1).[3]

In general, a vertical well drilled and completed in a tight gas reservoir must be successfully stimulated through fracking to produce at commercial gas-flow rates and volumes (Holditch, 2006). Under these circumstances, a large fracking treatment is required to produce gas economically. In some naturally fractured tight gas reservoirs, horizontal wells can be drilled, but these wells also need to be stimulated through fracking.

A schematic of natural gas geology and production is provided in Figure 1 below.

[3] On 28 September 2012 Santos commenced the first Australian commercial production of shale gas at vertical shale well Moomba 191 in the Cooper Basin (Santos, 2012, p. 15). It had an initial flow rate in excess of 3 million standard feet (mmscf) per day with an estimated ultimate recovery of 3 billion cubic feet (Bcf) after 12 years in service.

Figure 1: Schematic of Natural Gas Geology and Production



Source: U.S. Energy Information Administration (2022).

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.

If the experience in CSG is any indicator, large-scale shale gas extraction in Australia is likely to generate a high level of public interest and debate; broad sections of the Australian community are expected to be concerned about the environmental, social and public health impacts of shale gas operations (Knight & Bell, 2014). In many cases, the environmental legacy associated with the extraction of gas from shale overshadows the economic benefits, including groundwater and drinking water contamination as well as earthquakes (Cooper, Stamford, & Azapagic, 2016, p. 772). Social and economic concerns have also been raised, including noise, increased traffic, and possible conflicts of interest associated with royalties from mineral rights (Cooper, Stamford, & Azapagic, 2016, pp. 772-773).

The development of shale gas comes with a sobering array of costs that include a technological sophistication that makes drilling and fracking prone to accidents; the degradation of air, water, and land; enhanced risk of earthquakes and seismic events; and highly uncertain reserves with unclear profit margins (Sovacool, 2014, pp. 254-255).

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).

2.3 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 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.

2.4 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 per cent 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 per cent of global LNG imports. In 2021 China overtook Japan for the first time as the world's top LNG importing country.

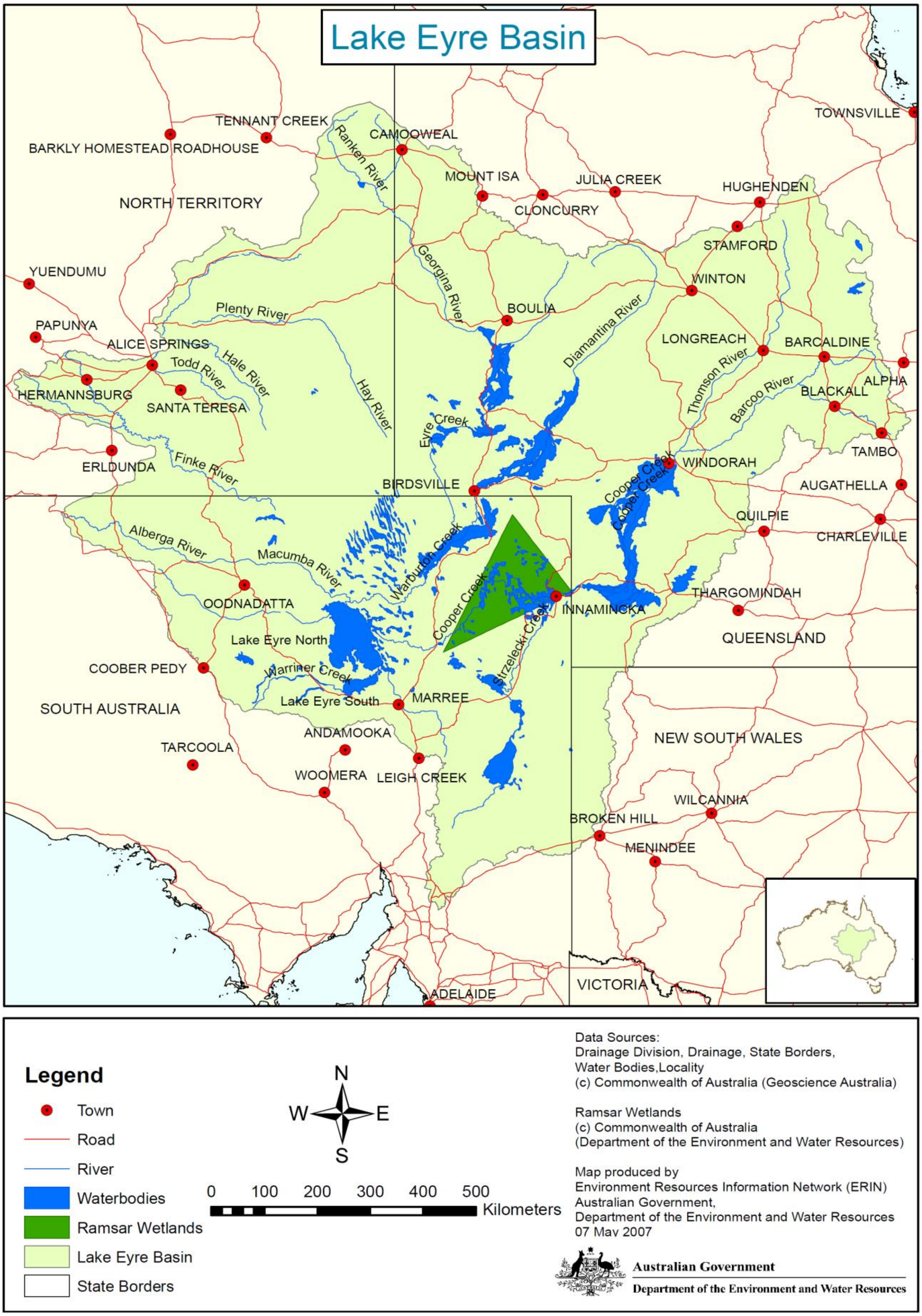
In 2021 Australia was the largest exporter of LNG, accounting for 21.1 per cent of global exports, closely followed by Qatar accounting for 20.7 per cent, and the United States accounting for 18 per cent (International Group of Liquefied Natural Gas Importers, 2022).

3. Lake Eyre Basin and Underlying Basins

3.1 Lake Eyre Basin

The Lake Eyre Basin (LEB) is a shallow endorheic (hydrologically landlocked) basin extending across the NT, SA, NSW, and Queensland (Wakelin-King, 2022, p. 113). It covers nearly one sixth of the Australian continent and is one of the largest internally draining river basins in the world (Fielder, Grady, & Broadbent, 2019, p. vi). A map of the LEB is provided in Figure 2 below.

Figure 2: Lake Eyre Basin



The vast riverine ecosystems and wetlands of the LEB cover 73,903 km^2 and are in a pristine condition when compared to the more developed basins such as the neighbouring Murray-Darling Basin (Fielder, Grady, & Broadbent, 2019, p. vi). The region consists of several river basins including the Georgina, Diamantina, Thomson and Barcoo rivers that form Cooper Creek flow from western Queensland into South Australia, whilst the Finke, Todd and Hale rivers flow from the NT; making their way to Lake Eyre (Admin, 2018). None of these interconnected water systems within the basin flow continuously due to the predominant low gradient within the area causing natural diversions across the landscape. As the volume of water increases, the rate of flow decreases downstream as water is gradually dispersed through waterholes, wetlands and floodplains. For the rainwater that does travel the distance to Lake Eyre, it drains internally through evaporation and ground seepage and contributes to the development of this large salt lake. The LEB is considered to have the lowest annual runoff compared to other internal drainage basins across the world.

Queensland's Channel Country is the source of most of the water in the LEB (FitzSimons, 2010). The river systems of western Queensland, such as the Georgina, Diamantina and Cooper Creek catchments have been subjected to relatively low anthropogenic disturbance and all presently lack major structures that would regulate flow (Fielder, Grady, & Broadbent, 2019, p. 19). Unlike the Murray-Darling system to its east, the Channel Country has never been cultivated, dammed or irrigated (FitzSimons, 2010).

At the heart of the Basin lies Kati Thanda–Lake Eyre (Department of Agriculture, Water and the Environment, 2020). At 9,700 square kilometres in area, it is the fourth largest terminal lake in the world. Australia's lowest point, 15 metres below sea level, is found on the bed of the Lake.

Although thinly populated, the LEB contains towns and indigenous homelands, and supports industries in the pastoral, agricultural, defence, conservation, tourism, and resources sectors (Wakelin-King, 2022, p. 113).

The LEB is part of the arid rangelands where most land is leased for grazing (Department of Agriculture, Water and the Environment, 2020). Much of this Basin is owned by Aboriginal people or is under Native Title claim.

About 60,000 people live scattered across the LEB (Department of Agriculture, Water and the Environment, 2020). They live in towns, such as Longreach and Alice Springs, small settlements like Marree, or isolated homesteads on huge grazing properties. There are also mining developments, notably the Moomba Gas Fields, and Aboriginal communities and outstations, such as Alpurrurulam and Nepabunna.

The LEB is the youngest of a succession of sedimentary basins occupying this region over geological time (Wakelin-King, 2022, p. 117). In terms of the existence of as yet undeveloped unconventional gas resources within the LEB, they are most likely to be found within the Cooper Basin along with the overlying Eromanga Basin and the Georgina Basin.

An independent scientific panel commissioned by the Queensland Government recommended in relation to the LEB that:

> *Infrastructure for mining and petroleum/gas activities should not be allowed in the floodplains because of flow alterations, fish passage issues and major impacts to floodplain ecosystems. (Fielder, Grady, & Broadbent, 2019, p. 25)*
>
> *Unconventional petroleum and gas production be an unacceptable use in the Designated Precinct (DP) (Fielder, Grady, & Broadbent, 2019, p. 41).*[4]

[4] The *Regional Planning Interests Act* (Qld) (RPI Act) defines describes Strategic Environmental Areas (SEA) (Fielder, Grady, & Broadbent, 2019, p. 2). The RPI Act manages the impact of resource and regulated activities on areas of regional interest and has designated Queensland's Channel Country as one of five SEAs within Queensland. The *Regional Planning Interests Regulation 2014* (Qld) (RPI Regulation) defines designated precincts (DP) within parts of a SEA (Fielder, Grady, & Broadbent, 2019, p. 3). These precincts consist of portions of an SEA where a higher level of protection applies than in the wider SEA. The Queensland's Channel Country has been designated as a SEA under the RPI Regulation. In the Channel Country, the DP parallels the whole of the SEA (Fielder, Grady, & Broadbent, 2019, p. 3).

3.2 Cooper-Eromanga Basins

The Eromanga Basin is a sedimentary basin encompassing an area of approximately 1 million km^2 in central Australia (Wecker, 1989, p. 379). It is the most extensive of three basins comprising the Great Artesian Basin, one of the world's largest artesian systems.

The Cooper Basin is a sedimentary basin that covers an area of around 130 000 km^2, is up to 2500 metres thick and occurs at depths between 1,000 and 4,500 metres below sea level (Robinson, et al., 2019, p. 947). The overlying Eromanga Basin covers the entire lateral extent of the Cooper Basin. The Eromanga Basin reaches more than 2,500 metres thick over the Cooper Basin (Hall, et al., 2019, p. 33). Overlying the Eromanga Basin is the LEB although this is less than 300 metres thick over the Cooper Basin. The Eromanga and Lake Eyre Basins contain the extensive groundwater system of the Great Artesian Basin. The Cooper Basin spans north-east SA and south-west Queensland (Ovenden, 2019, p. 928).

The Cooper Basin subregion within the overlaying central Eromanga Basin has constituted Australia's most important onshore petroleum province (Röth & Littke, 2022). Santos and Delhi first discovered commercial gas in 1963 (Ovenden, 2019, p. 928). First oil was discovered in 1970. Since then, the Cooper Basin has become a strategically important processing and transportation hub for produced gas and liquids.

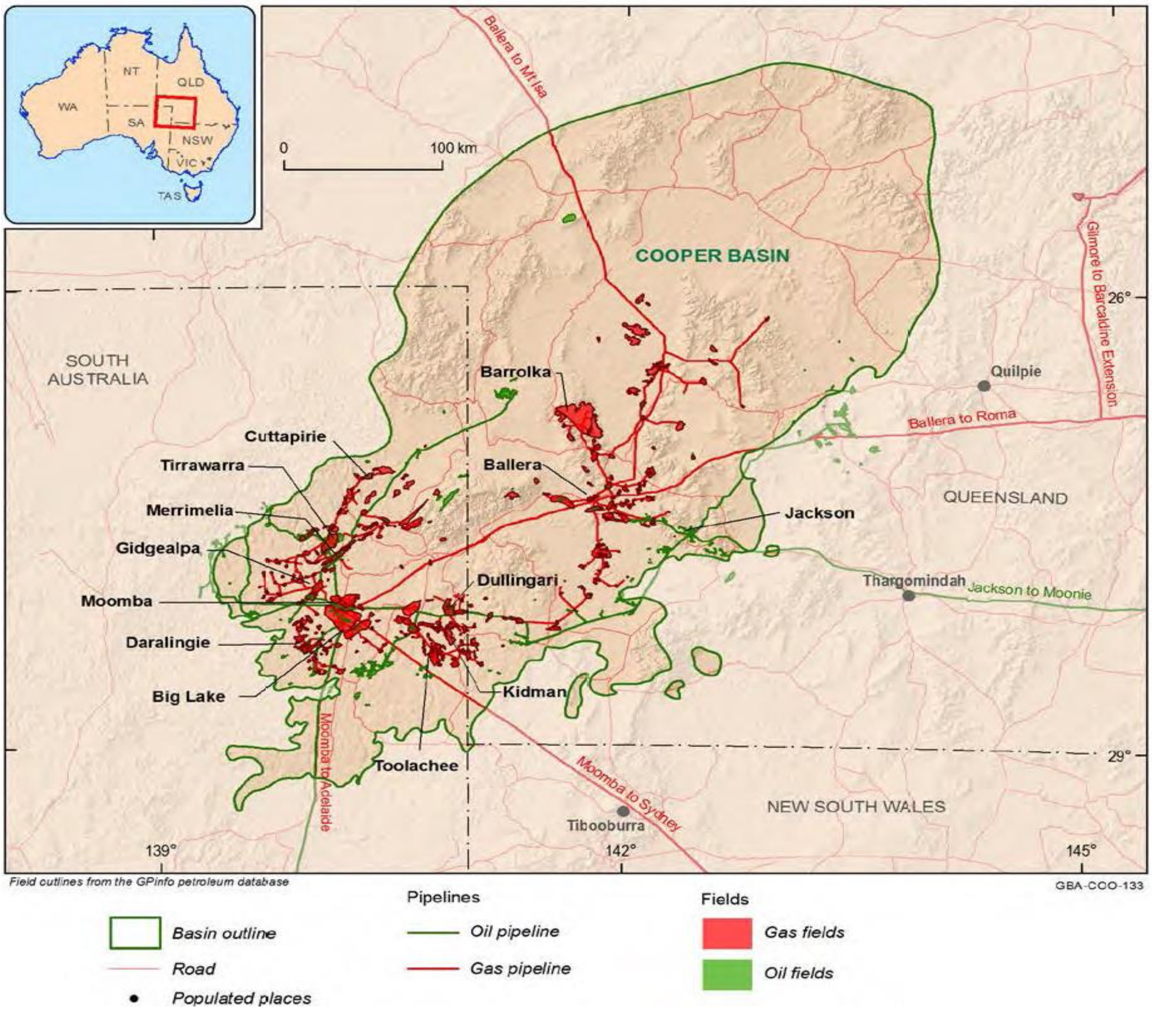
The Cooper Basin has been an important source of supply for the SA market via the Moomba to Adelaide Pipeline System (MAPs), and for the NSW market via the Moomba to Sydney Pipeline (MSP) (Australian Competition and Consumer Commission, 2016, p. 29). The South West Queensland Pipeline (SWQP) also runs from Wallumbilla to Moomba.

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 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).

A map of Cooper Basin petroleum fields, pipelines and production facilities is provided in Figure 3 below.

Figure 3: Cooper Basin Petroleum Fields, Pipelines and Production Facilities



Source: Lech, et al., (2020).

The Cooper Basin is considered highly prospective for unconventional gas including tight and deep coal gas resources, and has medium relative prospectivity for shale gas (Lech, et al., 2020, p. 163).

Given the Cooper Basin's existing conventional production and proximity to gas processing and pipeline infrastructure, the petroleum industry is currently exploring tight, shale and deep coal plays (Robinson, et al., 2019, p. 947).[5] Substantial gas infrastructure, including a gas pipeline servicing SA, Queensland and NSW markets, already exists (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 118).

3.3 Georgina Basin

The Georgina Basin is a sedimentary basin that covers an area of around 330 000 km^2 in the central-eastern Northern Territory that extends into western Queensland (Kruse, Dunster, & Munson, 2011, p. 28.1). The basin consists of two distinct domains: depocentres (where a rock formation has it maximum thickness) in the southern part of the basin (southern Georgina Basin), including the Dulcie and Toko synclines, and a central-northern platform (Munson, 2014, p. 111).

Several river catchments overlie the Georgina Basin, with most draining north towards the Gulf of Carpentaria, while parts of the Diamantina-Georgina (south to Lake Eyre) and Victoria–Wiso (northwest to Tanami–Timor Sea coast) are also observed (Hall, et al., 2018, p. 74). Most of these are

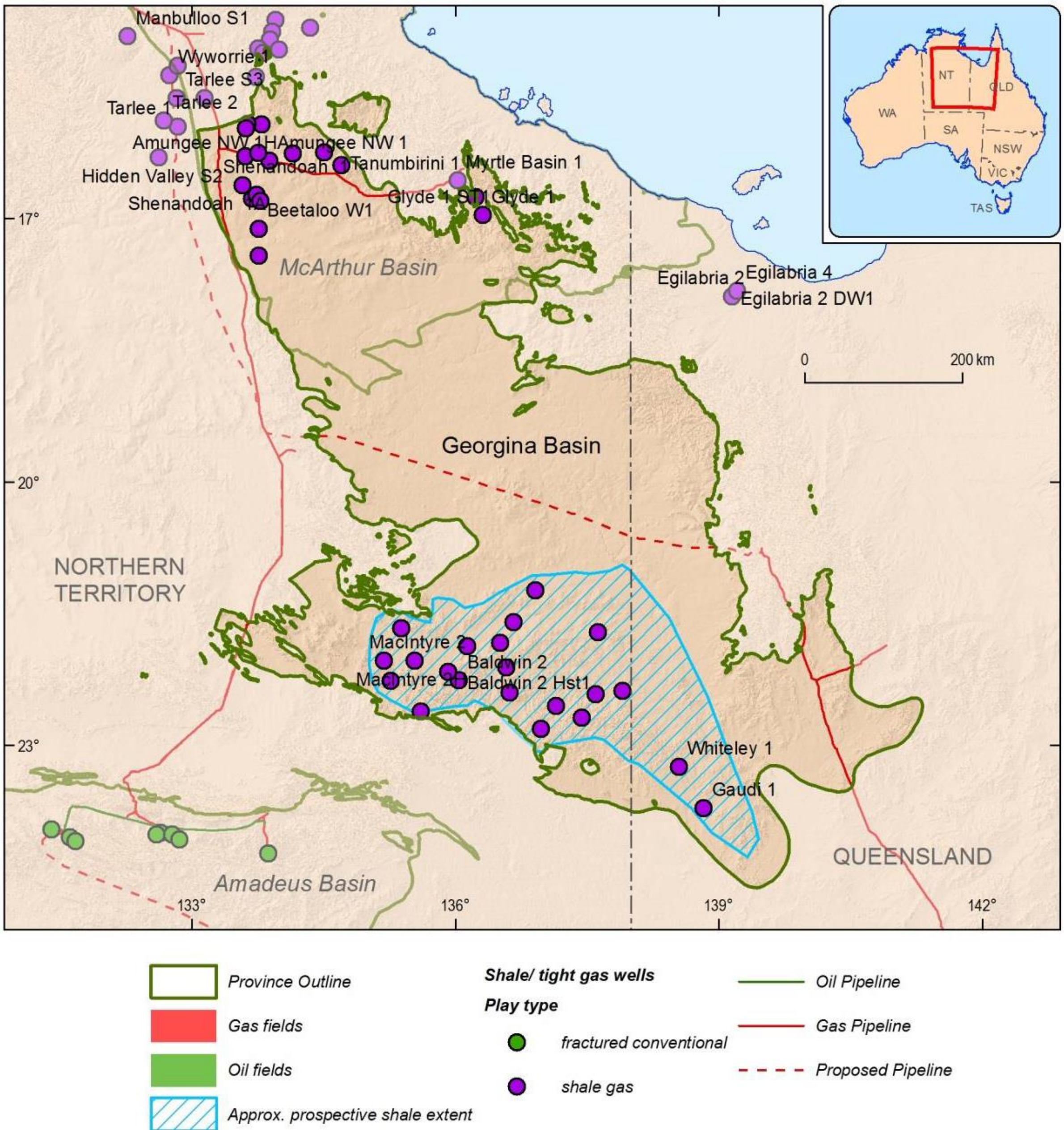
[5] A 'play' is defined as a set of known or postulated oil and or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type (Bradbury, Clement, & Down, 2015, p. 6n).

ephemeral, with strongly seasonal flow. There are two exceptions: the perennial Gregory and O'Shannassy rivers.

Within the Georgina Basin there are 9,700 km^2 of protected areas, including national parks (Limmen, Boodjamulla (Lawn Hill), Lytwelepenty /Davenport Ranges, Dulcie Range, and Camooweal Caves National Parks) and 6,500 km^2 of wetlands of national importance (Hall, et al., 2018, p. 74). The region is sparsely populated (basin population 3,700), with about half the area coinciding with Native Title areas (188,200km^2); the main land use is for grazing stock on native vegetation. The Georgina Basin has two small commercial centres located in Mount Isa and Alice Springs (Newman, 2015). Also, heavy rainfall from December to March can isolate road network and restrict access in the region.

The southern part of the Georgina Basin is considered to be among the most prospective onshore areas for oil and gas potential and to have world-class shale source rocks (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018, p. 93). A map of the Georgina Basin petroleum fields is provided below in Figure 4.

Figure 4: Georgina Basin Petroleum Fields



Source: Hall, et al., (2018).

4. Eastern Gas Region

4.1 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).[6]

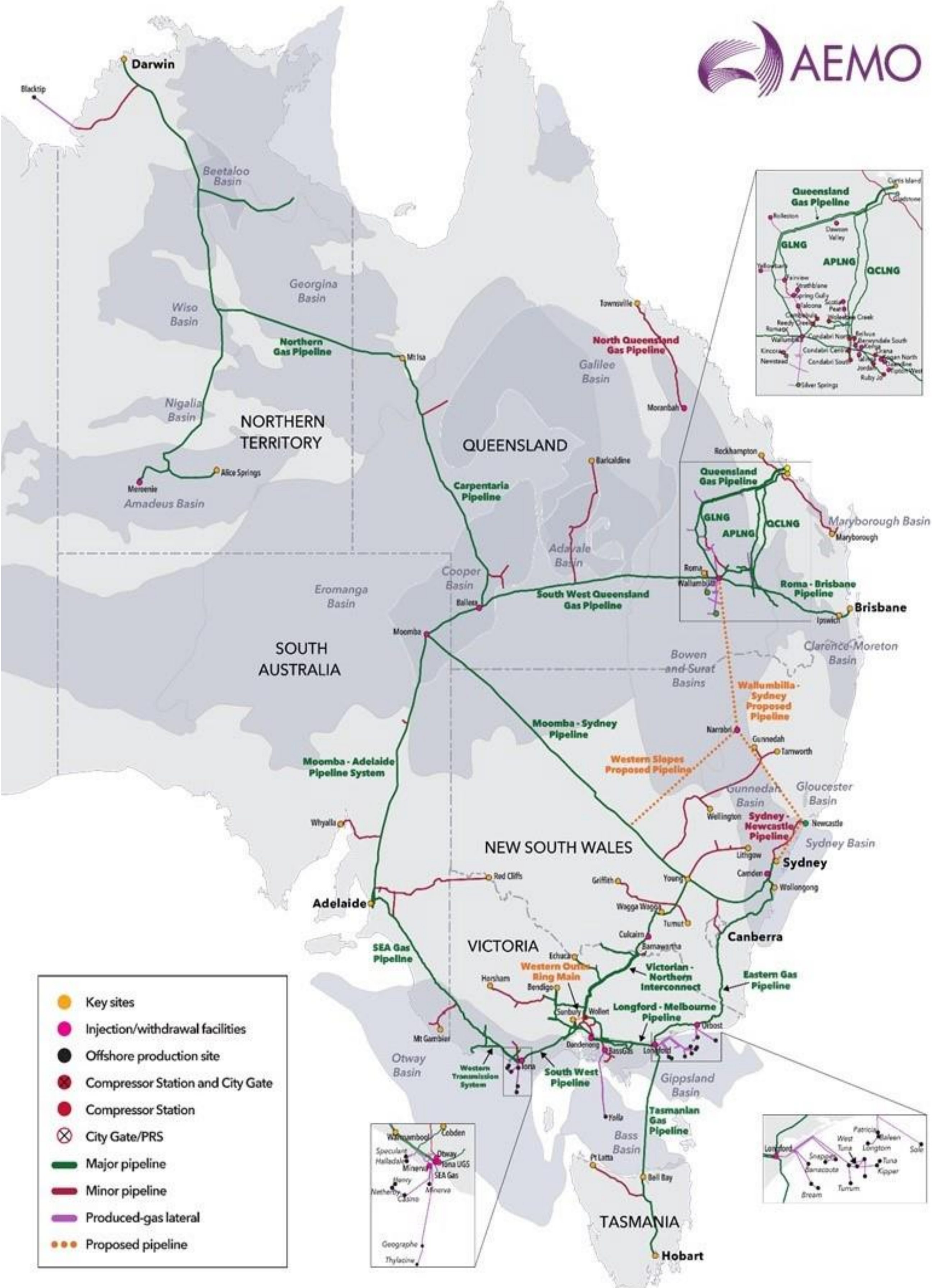
Gas production in the Eastern Gas Region began around 50 years ago (Australian Energy Regulator, 2018, p. 180). Relatively low prices at that time encouraged residential, commercial and industrial customers to use gas. Gas use later expanded into the electricity generation market, because the rapid responsiveness of gas powered turbines make them suitable for peak electricity generation capacity and combined cycle intermediate load generation. GPG also plays 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 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 5 below.

[6] 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).

Figure 5: Map of Basins, Major Pipelines and Load Centres for Eastern Gas Region



Source: Australian Energy Market Operator (2022, 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 north eastern 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:

- Queensland Curtis Liquid Natural Gas (QCLNG) commenced exporting LNG from its first train in January 2015 and from its second train in July 2015
- Gladstone Liquid Natural Gas (GLNG) commenced exporting LNG from its first train in September 2015 and from its second train in May 2016
- Australian Pacific Liquid Natural Gas (APLNG) commenced exporting from its first train in January 2016 and from its second train in October 2016 (Downey, Thomas, & Stone, 2019; Australian Competition and Consumer Commission, 2016, p. 24).

4.2 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 1 below.

Table 1: Gas Basins Serving the Eastern Gas Region in 2020

	Gas Production 12 months to December 2020	
Gas Basins	Petajoules (PJ)	Share of Eastern Australia Supply (%)
Surat–Bowen (Qld)	1,513	76%
Cooper (SA–Qld)	101	5%
Gippsland (Vic)	255	13%
Otway (Vic)	37	2%
Bass (Vic)	11	1%
Sydney and Gunnedah (NSW)	4	0%
Amadeus (NT)	15	1%
Bonaparte (NT)	47	2%
Eastern Gas Region Total	**1,983**	
Domestic Gas Sales	**631**	
LNG Exports	**1,352**	

Sources: EnergyQuest, *Energy Quarterly, March 2021* as cited by the Australian Energy Regulator (2021, p. 185).

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. 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, 2020a, 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 almost 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 per cent of NSW's gas has come from the Cooper Basin, around 55 per cent has come from Victoria and around 5 per cent 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 per cent 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) providing electricity for the equivalent of about 23,000 households in northwest NSW (Santos Ltd, 2019a). The Wilga Park Power Station is located to the west of Narrabri (Eastern Star Gas Limited, 2010).

In 2017 Santos applied to develop the NGP in the Gunnedah Basin (Australian Energy Regulator, 2021, p. 186). After encountering widespread opposition on environmental grounds, the project received consent from the NSW Independent Planning Commission in September 2020. In November 2020 the NSW Minister for the Environment granted approval to the project, however, Santos has yet to announce a final investment decision on the NGP.

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).

4.3 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 per cent of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2022).

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

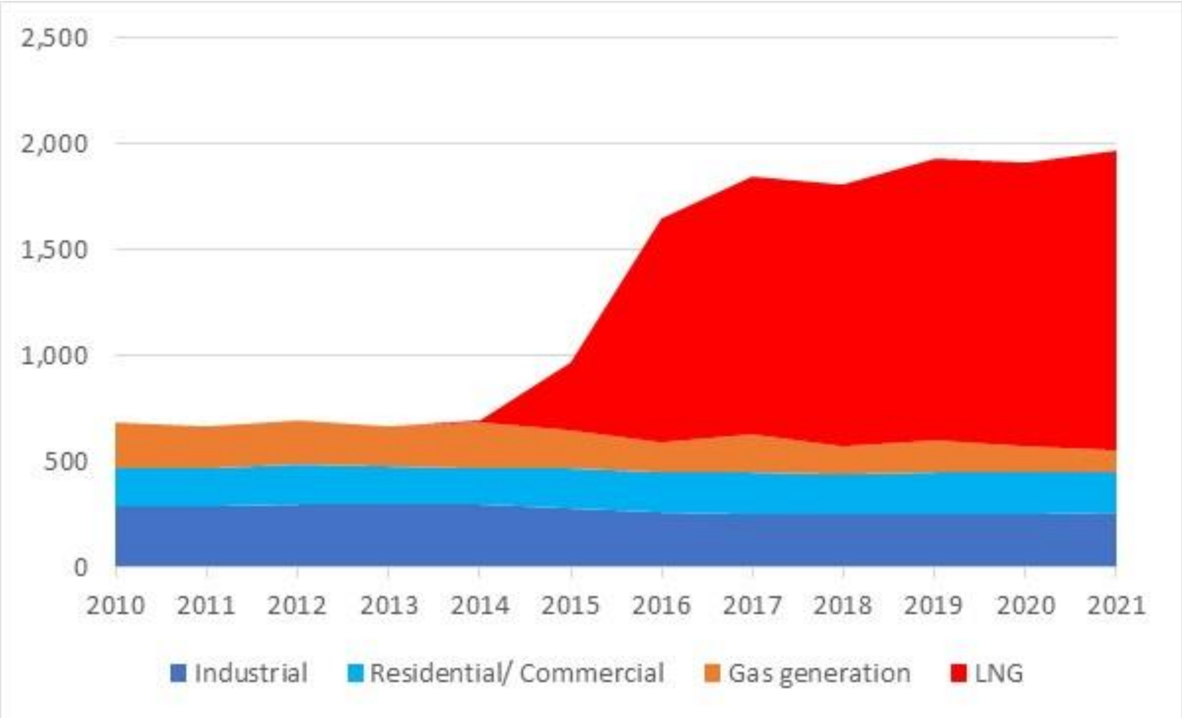
Table 2: Estimated Regional Consumption of Gas within the Eastern Gas Region by Sector - 2021

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 (2022).

Actual consumption of natural gas by sector is provided below in Figure 6 which outlines the significant ratcheting up of gas consumption by the LNG export projects since 2014.

Figure 6: Eastern Gas Region Natural Gas Consumption by Sector – 2010 to 2021 (PJ)



Source: Australian Energy Market Operator (2022).

5. Reserve and Resource Estimates

5.1 Classification of Gas Resources

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 per cent 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.

5.2 Reserve and Resource Estimates in the Eastern Gas Region and Onshore Northern Territory

Table 3 below sets out producers' best estimates of their 2P reserves and 2C resources in the Eastern Gas Region (onshore and offshore) and the Northern Territory (onshore only) as of 30 June 2021.

Table 3: 2P Reserves and 2C Resources as at 30 June 2021 (PJ)

Eastern Gas Region Basin	2P Reserves PJ	2C Resources PJ
Bowen Basin (Qld)	6,049	13,270
Surat Basin (Qld)	23,131	8,053
Galilee Basin (Qld)		2,788
Clarence-Moreton Basin (Qld/NSW)		688
Cooper Basin (SA/Qld)	1,003	1,912
Gippsland Basin (Vic)	1,968	2,231
Otway Basin (Vic)	655	231
Bass Basin (Vic)	145	44
Sydney Basin (NSW)	2	
Gunnedah Basin (NSW)	15	2,561
Total Eastern Gas Region	**32,968**	**31,758**
Onshore Northern Territory		
Amadeus Basin	245	196
McArthur Basin (Beetaloo Sub-basin)		7,032
Total NT (onshore)	**245**	**7,228**
Total Eastern Gas Region and NT	**33,213**	**38,986**

Source: Australian Competition and Consumer Commission (2022, p. 159).

The majority of 2P reserves in the Eastern Gas Region are located in the CSG fields of Queensland, with 70 per cent of 2P reserves located in the Surat Basin and 18 per cent in the Bowen Basin (Australian Competition and Consumer Commission, 2022, p. 162). The remaining 2P reserves are in offshore Victoria (8 per cent), the Cooper Basin (3 per cent), the Amadeus Basin (0.7 per cent), the Gunnedah Basin (0.05 per cent) and the Sydney Basin (0.007 per cent).

Like 2P reserves, the majority of 2C resources are in Queensland (Australian Competition and Consumer Commission, 2022, p. 163). As of 30 June 2021, there were 38,986 PJ of 2C resources in the Eastern Gas Region and onshore Northern Territory, 34 per cent of which were in the Bowen Basin, 21 per cent in the Surat Basin and 7 per cent in the Galilee Basin.

The McArthur Basin in the Northern Territory, which includes the Beetaloo Sub-basin, also contains a significant quantity of 2C resources (18 per cent), as does the Gunnedah Basin (7 per cent) (Australian Competition and Consumer Commission, 2022, p. 163). While CSG accounts for the majority of the 2C resources (64 per cent), other unconventional sources of gas (19 per cent) (e.g. tight gas and shale gas) located primarily in the Bowen, McArthur and Cooper basins, are starting to account for an increasing proportion of 2C resources over the last three years.

Gas producers can face a range of technical challenges when developing CSG and other unconventional gas fields, therefore a significant degree of uncertainty surrounds whether these contingent resources will be commercially recoverable in the future (Australian Competition and Consumer Commission, 2022, p. 163). Despite unconventional targets for shale gas being recognised across many Australian sedimentary basins, there have been no definitive tests that prove that any of these potential plays will flow gas at commercial rates (Close, 2015).

5.3 Estimates of Unconventional Gas Resources in the Cooper Basin

The Cooper Basin has seen some of the highest levels of unconventional focused exploration activity, with several companies and/or joint ventures (JV) evaluating and testing shale targets (Roseneath and Murteree Formations), deep coal gas and tight gas (mainly the Patchawarra Formation) (Close, 2015). However, recent drilling of unconventional gas wells has been sporadic, compared with other basins (eg the Beetaloo Sub-basin).

Beach Energy reported the first contingent shale gas resources (2200 PJ, 2 trillion cubic feet (Tcf)) in the Cooper Basin back in 2011; and in 2012 Santos booked the first shale gas reserves (2P ~3 PJ, 3 billion cubic feet (bcf)) on the results of production from the Moomba 191 well (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 98). The best estimate of contingent resources of unconventional gas resources available in the Cooper Basin by gas producers and prospecting companies based on research by Pegasus is around 5 Tcf. The U.S. Geological Survey (USGS) (2016) has also estimated contingent resources of tight gas of 25.74 Tcf and deep coal gas of 0.26 Tcf in the Cooper Basin. This is outlined in Table 4 below.

Table 4: Reported Unconventional Gas Contingent Resources (2C) in trillion cubic feet (Tcf) for the Cooper Basin

Company and Source	State	Assessment Area	Contingent Resources 2C	Play Type
Santos (2012) and Beach Energy (2020)	SA	PPLs 7, 8, 9, 11, 101, 102 11	0.30 Tcf	Shale gas and tight gas
Senex (2013)	SA	PEL 115 and PEL 516	0.84 Tcf	Tight gas
Senex (2013)	SA	PEL 516	0.70 Tcf	Shale gas
Senex (2013)	SA	PEL 90	0.42 Tcf	Deep coal gas
Drillsearch (2015)	Qld	ATP 940	0.77 Tcf	Shale gas and tight gas
Strike Energy (2015)	SA	PEL 96	0.21 Tcf	Tight gas and deep coal gas
Pure Energy (2020)	Qld	ATP 927P	0.33 Tcf	Basin centred gas
Icon Energy (2020)	Qld	ATP 855	1.57 Tcf	Shale gas and basin centred gas
USGS (2016)	SA / Qld	Entire basin	26.00 Tcf	Tight gas and deep coal gas

There are also very large estimates of potentially recoverable prospective unconventional gas resources in the Cooper Basin (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 98).

AWT International (Rawsthorn, 2013, p. 8) arrived at the best estimate of prospective shale gas resources in the Cooper Basin of 14 Tcf of wet gas, and 35 Tcf of dry gas, with the Eromanga Basin containing another 82 Tcf of dry gas. The U.S. Energy Information Administration (2013, p. III.14) has estimated that net of 15 per cent carbon dioxide content, there is risked shale gas in-place is 325 Tcf, with a risked, technically recoverable shale gas resource of 93 Tcf, including associated gas in the shale oil prospective area within the Cooper Basin.[7]

[7] According to the U.S. Energy Information Administration (2015, p. 5), the risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by

However, given that these estimates are based on limited data and little or no production history information, the initial estimates may decline with actual well performance data (Geoscience Australia and Bureau of Resources and Energy Economics, 2018, p. 98).

The 2018 Australian Energy Resources Assessment (AERA) report estimated there were prospective resources of shale gas of 138.3 Tcf and tight gas of 1019 Tcf in the Cooper Basin of which 5 per cent was estimated to be recoverable (Geoscience Australia and Bureau of Resources and Energy Economics, 2018).

Gas producers and prospectors have also published estimates on unconventional prospective gas resources in relation to acreage they currently occupy in the Cooper Basin. Santos (2012, p. 6) has said that it has access to 50 Tcf of unconventional prospective gas resources in the Cooper Basin estimated on a 2U basis. The total amount of unconventional prospective gas resources could be considerably higher as Santos generally operates joint ventures in its production and prospecting activities in the Cooper Basin. Pure Energy (2020) has said that it has unconventional prospective gas resources of 8.8 Tcf estimated on a mean original gas-in-place basis.[8] Icon Energy (2020, p. 6) has said that it has 28.5 Tcf of unconventional prospective gas resources in the Cooper Basin estimated on a 2U basis.

Reflecting on the future development of unconventional gas resources in the Cooper Basin, energy consultants Core Energy Group (2016, p. 7) have reflected:

> *The prospects for converting a part of these discovered unconventional resources to competitive reserves are realistic.*

According to the Core Energy Group (2016, p. 8), there are at least five distinct unconventional reservoir plays available in the Cooper Basin and the chances are high that at least one large accumulation of these unconventional plays will be commercialised. Those five unconventional plays are:

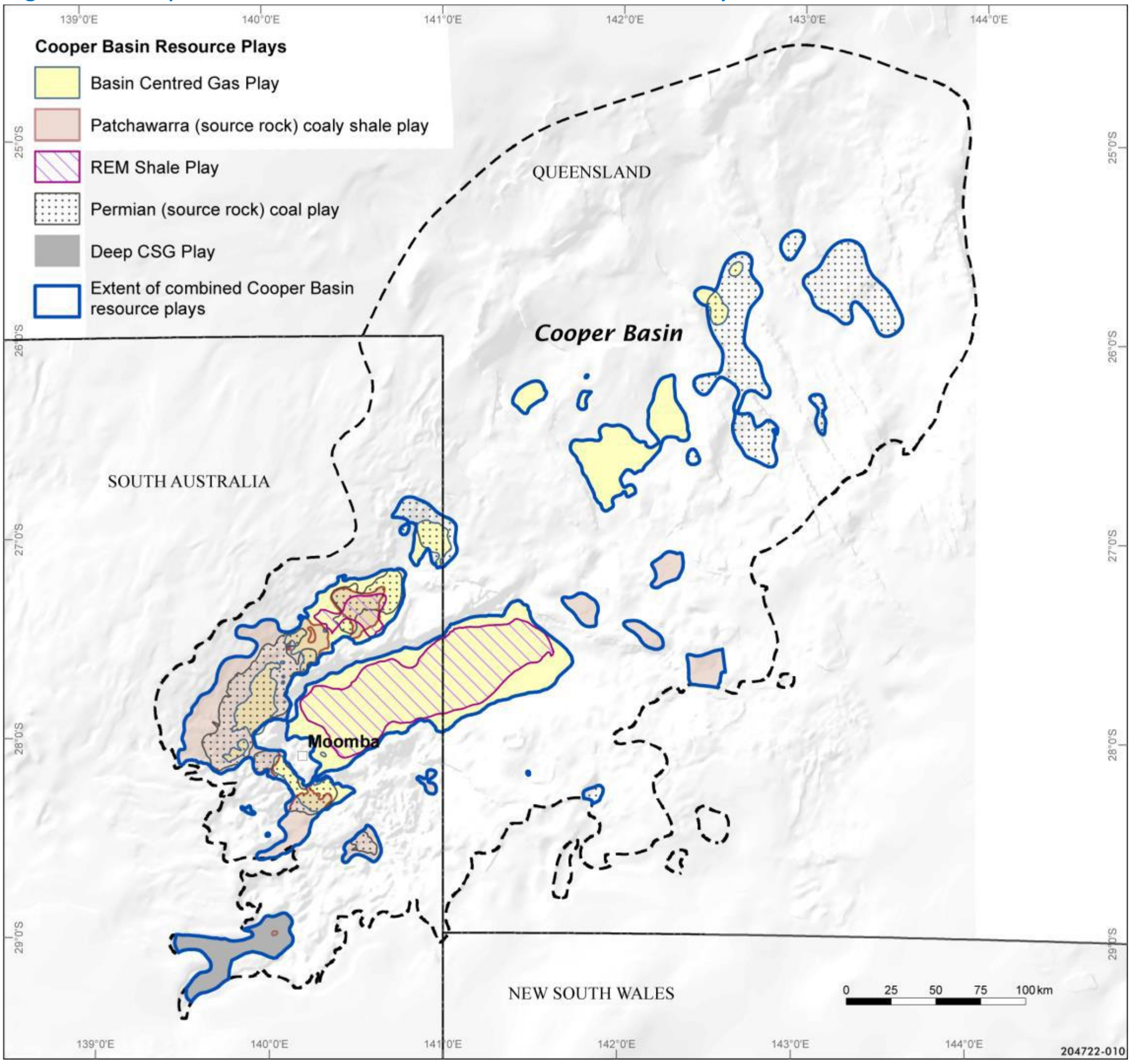
- Basin centred gas (BCG) (shale, siltstone, tight sandstone)
- Roseneath-Epsilon-Murteree (REM) (shale, siltstone, tight sandstone)
- Permian (source rock) coal
- Patchawarra (source rock) coaly shale
- Deep CSG (2016, p. 10).

These five unconventional gas plays in the Cooper Basin are outlined in Figure 7 below.

matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource.

[8] Gas-in-place is an estimated measure of the total amount of gas contained in a reservoir and, as such, a higher figure than recoverable gas (Cooper Energy, n.d.).

Figure 7: Cooper Basin Unconventional Gas Resource Plays



Source: Core Energy Group (2016, p. 10) taken from the South Australian Department of State Development's Energy Resource Division.

A summary of prospective gas resources in the Cooper Basin and Eromanga Basin is provided in Table 5 below.

Table 5: Estimates of Best Available Prospective Unconventional Gas Resources (2U) in the Cooper Basin and the Eromanga Basin (Tcf)

Basin	State	Best Potentially Recoverable Prospective Resources (2U)	Play Type	Source
Cooper Basin	SA / Qld	49.0 Tcf	Shale gas	AWT (Rawsthorn, 2013)
Eromanga Basin	SA / Qld	82.0 Tcf	Shale gas	AWT (Rawsthorn, 2013)
Cooper Basin	SA / Qld	93.0 Tcf	Shale gas	U.S. Energy Information Administration (2013)
Cooper Basin	SA / Qld	50.9 Tcf	Tight gas	AERA (Geoscience Australia and Bureau of Resources and Energy Economics, 2018)
Cooper Basin	SA / Qld	6.9 Tcf	Shale gas	AERA (Geoscience Australia and Bureau of Resources and Energy Economics, 2018)
Cooper Basin	SA / Qld	75.0 Tcf	Shale gas, tight gas and deep coal gas	Santos (2012)
Cooper Basin	Qld	8.8 Tcf	Basin centred gas	Pure Energy (2020)
Cooper Basin	Qld	28.5 Tcf	Shale gas and basin centred gas	Icon Energy (2020)

In late October 2021 the Queensland Government granted 11 exploration permits in the northern Queensland part of the Cooper Basin. These permits cover more than 250,000 hectares of land in the Channel Country bioregion of the LEB granted to gas company Origin Energy (Grounds & Morris, 2021). The leases give Origin Energy the right to explore for and produce petroleum, and test for petroleum production for a period of up to 10 years.

One of those exploration permits covers the area north of Lake Yamma Yamma (PL 1099). Lake Yamma Yamma is the largest dryland lake in Queensland, Australia (~800 sq. km), located near the northeast corner of the South Australian and Queensland borders (Mann & Amos, 2022, p. 32). Nine of those exploration permits lie west of the town of Windorah (PL 1094, PL 1095, PL 1096, PL 1097, PL 1100, PL 1101, PL 1102, PL 1103, PL 1104), and another permit lies west of the town of Jundah (PL 1098).

However, Origin Energy still requires an Environmental Authority under Queensland legislation before commencing any resource development (Grounds & Morris, 2021). The granting of the petroleum leases means unconventional gas production could occur in the Channel Country for the first time which, with the shale geology of the LEB, will likely require fracking.

While the Cooper Basin initially appeared favourable for shale development, a key risk was that the shales were deposited in a lacustrine environment (U.S. Energy Information Administration, 2013, p. III.8).[9] Lacustrine shales often have higher clay contents with uncertainty on how the shales will respond to hydraulic stimulation treatments, in comparison with lower clay content marine shales. In addition, high carbon dioxide volumes have been noted in the deeper troughs in this basin.

Based on the encouraging desktop studies by the U.S. Energy Information Administration, Chevron, Santos and Beach Energy began an ambitious exploration program for shale gas in the Cooper Basin,

[9] Lacustrine deposits are sedimentary rock formations which formed in the bottom of ancient lakes.

however, the results were disappointing (Bethune, 2020). In 2014 it was reported that gas flows from some shale gas wells in the Cooper Basin had declined at much faster rates than anticipated (Macdonald-Smith, 2014).

For the year ended 31 December 2014 Santos (2015) wrote down the value of its unconventional gas resources in the Cooper Basin by $70 million, despite having connected three shale gas wells to its existing production infrastructure in the Cooper Basin. For 2015 Santos (2016, p. 61) wrote down the value of its unconventional gas resources in the Cooper Basin by a further $23 million. Then for 2016 Santos (2017, p. 78) wrote down the value of its unconventional resources in the Cooper Basin by a further $49 million, writing off the recoverable value of its investment entirely.

In March 2015 U.S. based oil and gas multinational Chevron announced that it had pulled out of the Nappameri Trough unconventional gas project in the Cooper Basin, leaving the other joint venture partners Beach Energy and Icon Energy to go it alone (Wilkinson, 2015). In announcing its withdrawal from the project, Chevron said that the opportunity did not align strategically with Chevron's global exploration and development portfolio (Forster, 2015).

In late August 2016 Beach Energy downgraded contingent resources of shale gas in the Cooper Basin as then Chief Executive Matt Kay said the technical challenges of getting shale from the Cooper Basin in Central Australia appeared too great to overcome (Chambers, 2016). In relation to producing shale gas from the Cooper Basin, Matt Kay commented:

> *It's a challenging proposition for us and everyone else as well.*
>
> *We had a very good look at the results from our previous drilling campaign and studies and we just felt it's pretty challenging to commercialise — it's very high cost to go up and try to crack the code. (Chambers, 2016)*

54 Estimates of Unconventional Gas Resources in the Georgina Basin

The Arthur Creek Formation is considered to contain the most prospective unconventional gas targets in the Georgina Basin (Hall, et al., 2018). The unconventional potential comprises gas in fractured shale and other tight reservoirs, including fractured/vuggy silty dolostone of the upper Arthur Creek Formation and fractured silty shale of the lower Arthur Creek Formation (Munson, 2014, p. 141).

An assessment of the unconventional hydrocarbon plays for the eastern Toko Syncline of the Georgina Basin by consulting geologists DSWPET Pty Ltd (Warner, 2011) estimated 2U prospective technically recoverable gas resources of 11 Tcf in the upper Arthur Creek Shale (prospective area 4,531 km^2) and 13 Tcf in the lower Arthur Creek Shale (prospective area 4,068 km^2).

AWT International (Rawsthorn, 2013, p. 8) arrived at the best estimate of prospective shale gas resources in the Georgina Basin of 50 Tcf of dry gas for the Arthur Creek Formation over a prospective area of 14,433 km^2.

The U.S. Energy Information Administration (2013, p. III.36) has estimated there is risked shale gas in-place is 67 Tcf, with a risked, technically recoverable shale gas resource of 13 Tcf. This consists of technically recoverable shale gas resources for the lower Arthur Creek Formation of 8 Tcf in the Dulcie Syncline and 5 Tcf in the Toko Syncline.

A summary of 2U prospective gas resources estimated for the Georgina Basin is provided in Table 6 below.

Table 6: Estimates of Best Available Prospective Unconventional Gas Resources (2U) in the Georgina Basin (Tcf)

State / Location	Best Potentially Recoverable Prospective Resources (2U)	Play Type	Source
Qld (upper Arthur Creek)	11 Tcf	Shale gas	DSWPET Pty Ltd (Warner, 2011)
Qld / NT (lower Arthur Creek)	13 Tcf	Shale gas	DSWPET Pty Ltd (Warner, 2011)
Qld / NT (Arthur Creek Formation	50 Tcf	Shale gas	AWT (Rawsthorn, 2013)
NT (lower Arthur Creek Formation in the Dulcie Syncline)	8 Tcf	Shale gas	U.S. Energy Information Administration (2013)
Qld / NT (Toko Syncline)	5 Tcf	Shale gas	U.S. Energy Information Administration (2013)

Around 22 wells have been drilled in the southern Georgina Basin targeting shale oil, shale gas and basin-centred gas plays (Hall, et al., 2018, p. 56). However, drilling results to date have met with mixed success.

In terms of shale and tight gas prospectivity, the Georgina Basin has been ranked as moderate, reflecting the relatively poor results of recent exploration with a low–moderate confidence reflecting sparse data distribution (Hall, et al., 2018, p. vi).

The development of shale or tight gas plays in the Georgina Basin would also require major additional infrastructure development (Hall, et al., 2018, p. vii). There are currently no gas processing facilities and the prospective area the basin lies over 200 km from existing pipeline infrastructure. The Georgina Basin is also only poorly to moderately well serviced by road and rail networks, and is sparsely populated with few townships.

In November 2014 Norwegian international oil and gas company Statoil withdrew from any further activity in relation to permits EP 127 and EP 128 in the southern Georgina Basin following disappointing results based on drilling and testing (Baraka Energy & Resources Ltd, 2014).

In late February 2017 French international oil and gas company Total withdrew from its joint venture exploration operation in the Queensland part of the southern Georgina Basin (Central Petroleum, 2017).

According to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018, p. 96) in relation to the Georgina Basin:

> *There remains a great deal of uncertainty about the ability of the rocks within the basin to generate and host significant volumes of hydrocarbons. In this respect, the Georgina Basin lags behind the Beetaloo Sub-basin, so any discovery made today would almost certainly be more than three years from commercialisation and potentially more than a decade.*

6. Gas Prices and Gas Production Costs for the Eastern Gas Region

6.1 Future Gas Prices

2021 saw a surge of corporate concerns about net zero by 2050 and decarbonisation of the economy (Lewis Grey Advisory, 2021, p. 8).[10] 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. The newly elected Albanese Commonwealth Government has committed to reducing Australia's greenhouse gas emissions by 43 per cent 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).

The Australian Energy Market Operator (AEMO) (2022, pp. 15-16) in its 2022 *Gas Statement of Opportunities* (GSOO) has used a number of different scenarios exploring the speed and extent of gas sector transformation and has modelled those it considers are most relevant. Those scenarios are:

- ***Step Change*** is a future with a rapid transition towards net zero emissions economy wide. This includes significant levels of electrification (consumers shifting from gas to electricity) early on, as the electricity sector decarbonises with increasing renewable energy penetration and retiring coal generation.
- ***Progressive Change*** also targets net zero emissions, but the trajectory to achieve it is quite different from *Step Change*. The scenario reflects slower action across the economy, allowing time for technologies to develop, but relies on very strong transformation efforts later to get to net zero by 2050.
- ***Hydrogen Superpower*** describes a future with very strong environmental objectives globally, where Australia leverages its low-cost renewable resources to become a major exporter of hydrogen to countries that rely on imported energy. The scenario assumes higher growth in population and the economy overall as a result. Hydrogen is also used domestically to offset gas consumption, with reduced focus on electrification.
- ***Strong Electrification*** reflects a similar high-growth future to *Hydrogen Superpower*, retaining the higher economic and population growth assumptions, but with minimal hydrogen adoption. Instead, a very high level of electrification is assumed.
- ***Low Gas Price*** examines a likely upper bound to gas demand, with lower gas prices and no coordinated action for the gas sector to contribute to Australia's net zero commitment.

According to the AEMO (2022, p. 16), the scenarios have been defined based on specific assumptions, refined through extensive consultation with stakeholders. These include assumptions about the degree of electrification of existing gas demand, uptake of energy efficiency measures, hydrogen demand, and the technology used to produce hydrogen. Stakeholders identified *Step Change* as the scenario they considered the most likely pathway for Australia's energy sector. For the gas sector, *Step Change* projects tangible and rapid reductions in gas consumption, particularly as consumers electrify their energy needs.

The scenarios *Strong Electrification and Low Gas Price* have been developed for the purposes of sensitivity analysis (Australian Energy Market Operator, 2022, p. 16).

In the 2022 GSOO the AEMO abandoned development of a ***Slow Change*** scenario that had been used in previous GSOO editions. In the 2021 GSOO the ***Slow Change*** scenario was characterised by challenging economic conditions resulting in a slow-down of the energy transition, reflected in slower changes in technology costs, and a more challenging environment in which to make the

[10] 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.).

upfront investments required for significant emissions reduction (Australian Energy Market Operator, 2021, p. 16).

As part of the 2022 GSOO, AEMO (2022b, p. 6) constructed an energy supply model to simulate daily gas supply and demand balances over a 20-year timeframe. The model computes energy balances at all levels of a gas system from reservoirs, basins or terminals to the demand centres, in each gas network node and time period, and supplies energy services at minimum total system cost (Australian Energy Market Operator, 2022b, p. 6). Outputs consist of gas productions, pipeline flows, and potential shortfalls.

AEMO (2022, p. 26) also engaged Lewis Grey Advisory (LGA) to prepare the wholesale contract gas price forecasts for the 2022 GSOO. In turn, LGA (2021, p. 9) has projected gas prices in the Eastern Australian natural gas market (NSW, VIC, Queensland, SA and Tasmania) over the period 2021-2052, taking into account exports from Gladstone and the potential to import LNG to the domestic market at Port Kembla. According to LGA, eastern Australian gas market prices are largely determined by contract negotiation between producers and buyers, hence the projections focus on delivered average annual contract prices, including transmission costs, applicable to large industrial consumers, with high load factors.

LGA (2021, p. 11) based its gas price forecasts on a demand-supply balancing methodology that captures the features of the eastern Australian gas market. It is based on the assumption that suppliers try to maximise prices subject to competition with other suppliers and consumer price resistance. Interaction of eastern Australian domestic prices with global LNG prices was taken into account by LGA directly by modelling the two markets in parallel, due to the LNG export terminals competing with domestic gas users for the same limited onshore gas reserves.

On the supply side, LGA (2021, p. 12) linked production capacity to remaining gas reserves with potential gas supply for new contracts coming from uncontracted capacity. Development of undeveloped 2P reserves was assumed to be followed by 2C resources (separately for each producer) and supply costs are based on independent estimates of undeveloped 2P and 2C production costs.

Demand projections undertaken by LGA (2021, p. 20) were accompanied by underlying gas price projections. If sufficient supply was not available at that price, demand was reduced until supply matched demand.

LGA (2021, p. 20) based its global LNG demand forecasts based on projections prepared by the International Energy Agency (IEA) (2021) in its *World Energy Outlook 2021* publication and the Oxford Institute for Energy Research (OIES) *Energy Transition: Modelling the impact of Natural Gas* publication (Fulwood, 2021).

In the opinion of Pegasus, the gas price forecasts prepared for the 2022 GSOO, taking account of both the developments in the Eastern Gas Region and global LNG markets, provide the most plausible likely trajectory for both domestic and global markets in relation to gas over the next thirty years out to 2050.

6.2 Gas Production Costs

In its modelling for the AEMO, LGA (2021, p. 23) has set new capacity development costs based on undeveloped 2P reserves costs and 2C resources costs. However, in relation to the development costs of undeveloped gas resources, LGA (2021, p. 23) has warned:

> *Production costs are uncertain compared to other parameters used in the modelling, as they are not revealed by gas producers and even the producers cannot be certain about the costs of developing 2C resources.*

The technology such as horizontal wells, multi-well pads and hydraulic fracturing is available to produce shale gas and tight gas in Australia, however, production costs are likely to be significantly higher than those in North America and the lack of infrastructure will further add to costs (Cook, et al., 2013). In turn, the production of shale gas will not be cheap.

Shale gas production differs from conventional gas and CSG in that the shale gas well production decline rate is rapid, meaning that capital expenditure needs to be approximately maintained each year because of the need to drill and complete new wells to maintain production from a field (Cook, et al., 2013, p. 23).

Sustainable shale gas development in Australia requires that suppliers receive a price for the gas they produce that at least covers their marginal cost of production (Cook, et al., 2013, p. 23).

The revenue stream from a shale gas field each year is thus the consolidated gas production from these wells, times the gas price (Cook, et al., 2013, p. 92). The capital cost each year comprises the cost of drilling and fracking and any up-front land lease costs prior to the drilling. Shale gas is different to a conventional investment, since the capital cost are ongoing as more wells are drilled over the life of the investment.

Based on its early experience in drilling Australia's first shale gas well in the Cooper Basin, Santos (2012, p. 17) contended that shale gas could be commercially produced in the Cooper Basin. Santos said that estimated well and connection costs were $10 million for drilling vertical wells with an estimated recovery per well of 3 to 6 Bcf, with horizontal wells providing the opportunity for significant additional value enhancement. Santos contended that at a price of $6 per GJ vertical shale wells were economic.

In a 2013 committee report commissioned by the Australian Council of Learned Academies (ACOLA), chaired by Professor Peter Cook of the University of Melbourne (Cook Report), found that:

> *… shale gas will not be cheap gas in most circumstances. It will require a relatively high price to make it profitable to produce. … In Australia, shale gas will require a price of the order of $6-9 a gigajoule to make its production and transport profitable … (Cook, et al., 2013, pp. 13-14)*

The Core Energy Group (2016, p. 52) estimated in 2016 the cost of developing unconventional gas in the Cooper Basin would be as low of $4.82 per GJ based on global best practice, however, in reality this would be closer to $6 per GJ, as at 1 July 2015. On the other hand, Core Energy Group estimated the production of conventional gas in the Cooper Basin cost was $3.43 per GJ while an infill program would cost $6.55 per GJ.[11]

The Core Energy & Resources (2019) estimated in November 2019 that the cost of developing unconventional gas in the Cooper Basin would be $7.12 to $7.63 per GJ (in real July 2019 terms).

For the 2021 GSOO, energy consultants Wood Mackenzie estimated the production costs for developing 2C resources in the Cooper Basin consisting of conventional, shale and deep bed coal would be $6.32 to $11.12 per GJ (in 2020 real terms) (Australian Energy Market Operator, 2021a).

For the preparation of the 2022 GSOO as part of the LGA (2021, p. 23) modelling exercise, the AEMO provided LGA with updated gas production cost estimates with a low, medium and high cost estimates. The gas production cost estimates provided by AEMO allowed for the following scenarios:

1. The ***Slow Change*** scenario used high production cost estimates.
2. The ***Low Gas Price*** scenario used Low production cost estimates.
3. The other scenarios used the medium production cost estimates

The costs associated with these scenarios are outlined in Table 7 below.

[11] Infill drilling means drilling additional wells, often between the original development wells in order to produce unrecovered petroleum (Azuokwu, Yerima, Ngubi, & Obeta, 2016, p. 2005). Infill drilling involves drilling new wells in an existing field within the original well patterns for the purpose of more efficient recovery of petroleum from the reservoir. Generally, infill drilling can be considered feasible and successful as long as the amount of production increment covers the cost of the extra wells and associated pipe works at small financial risk.

Table 7: AEMO Average Gas Production Costs Weighted by Reserves/Resources as on 31 December 2020 ($ per GJ)

	Slow Change Scenario	Low Gas Price Scenario	All Other Scenarios
Undeveloped 2P Reserves	$5.79	$3.82	$4.82
2C Resources	$8.18	$4.81	$7.51

Source: LGA (2021, p. 24).

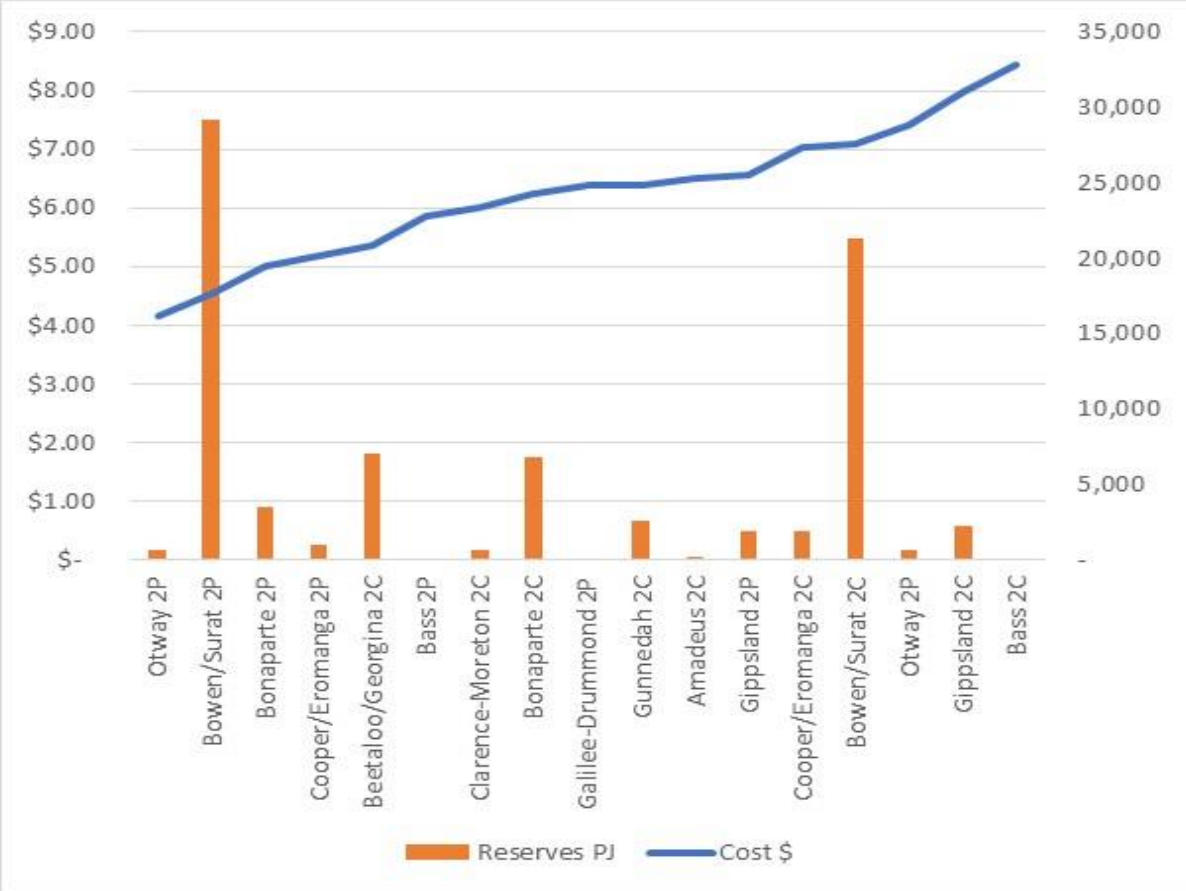
For the 2022 GSOO, the AEMO (2022b, p. 7) based its estimates of gas production costs incorporating Rystad Energy break even costs and previous GSOO inputs, adjusted to include return on capital. In this case, the cost of developing 2C gas resources in the Cooper Basin, presumably including unconventional gas, has been estimated at $7.02 per GJ (in 2021 real terms) (Australian Energy Market Operator, 2022c).

In relative terms, the development of 2C contingent resources in the Cooper Basin ranks 13 out of 17 actual and undeveloped gas projects in terms of production costs.

There are 12 developed and undeveloped gas projects with lower estimated production costs than the production of unconventional gas in the Cooper Basin. These 12 developed and undeveloped gas projects with estimated lower production costs represent some 53,700 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 8 below, whereby the estimated production costs for each project provides an effective gas supply curve for the Eastern Gas Region.

Furthermore, while the cost of producing from undeveloped 2C contingent resources in the Bowen and Surat basins appears to be slightly above the cost of undeveloped 2C contingent resources in the Cooper Basin, infrastructure transport costs to deliver gas to the Wallumbilla Hub will be considerably lower, in turn suggesting that undeveloped 2C contingent resources from the Bowen and Surat basins are likely to be developed long before any consideration is given to developing 2C contingent resources from the Cooper Basin.

*Figure 8: 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)**



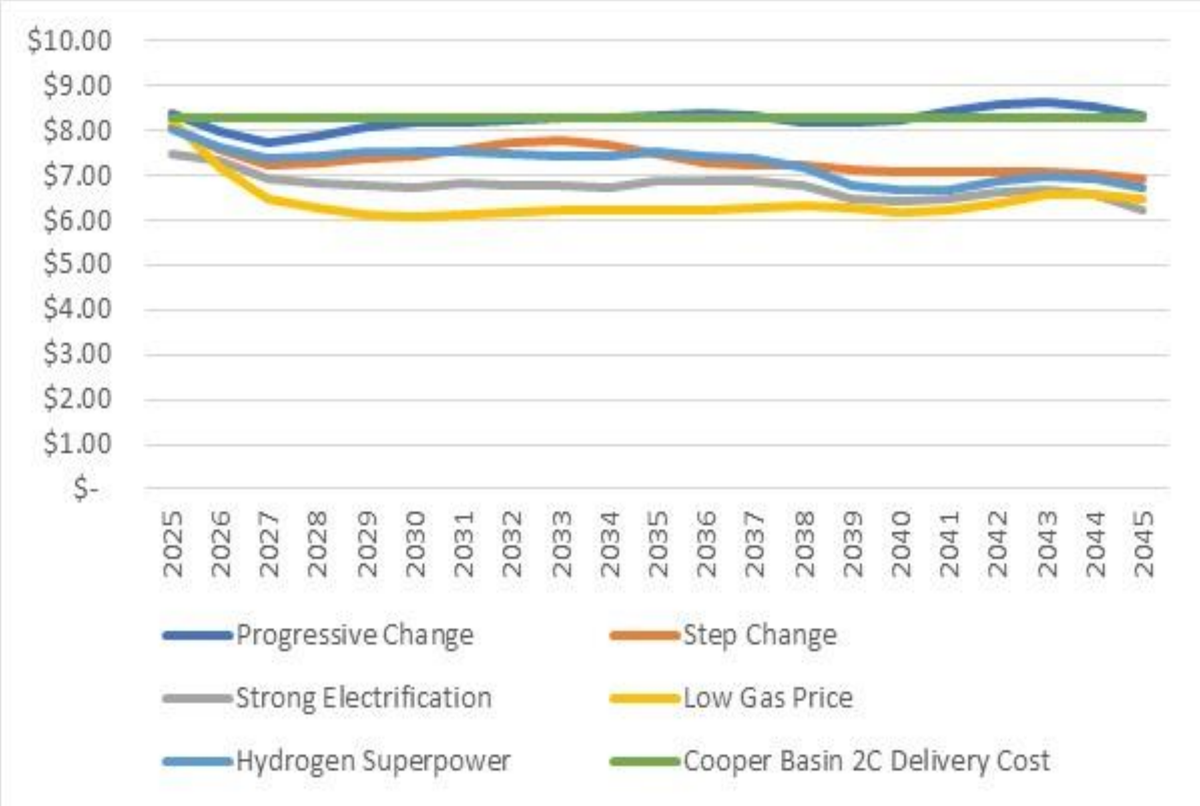
Sources: Production costs taken from AEMO (2022c), 2P reserves and 2C contingent resources taken from ACCC (2022, p. 159) except for the Bonaparte Basin that comes from AEMO (2022c).
* Note: Production costs from the Sydney Basin have been excluded as the Camden Gas Project is due to due to cease production 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.

Assuming that it would take at least until at 2025 to develop and make widely available 2C gas resources in the Cooper Basin, the LGA forecasts for wholesale gas prices at the Wallumbilla Hub as published in the 2022 GSOO for all scenarios have been compared to the estimated production cost of 2C resources from the Cooper Basin plus transport from the Cooper Basin to the Wallumbilla Hub along the South West Queensland Pipeline (SWQP) (Cooper Basin 2C delivery cost) from 2025 onwards. This is shown in Figure 9 below. As can be seen in Figure 9, the delivery cost of 2C resources from the Cooper Basin to the Wallumbilla Hub generally exceeds the forecast Wallumbilla Hub wholesale prices under all scenarios.

While the AEMO (2022c) estimates production costs for 2C gas resources in the Beetaloo/Georgina Basin of $5.35 per GJ, it highly likely that this relates entirely to the development and production of unconventional gas in the Beetaloo Sub-basin. This is because any commercial gas discovery in the Georgina Basin would almost certainly be more than three years from commercialisation and potentially more than a decade according to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018, p. 96). Tamboran Resources (2022, p. 18) estimates that it can produce and deliver shale gas from the Beetaloo Sub-basin to the Eastern Gas Region by 2025 using existing pipeline infrastructure at between $6 to $7 per GJ, and deliver shale gas to the Wallumbilla Hub via a new pipeline by 2028 at $4 per GJ.[12]

[12] According to Tamboran Resources (2022, p. 18), upstream costs including operating costs and drilling capital expenditure in 2025 will be an estimated $2 to $3 per GJ in 2025, falling to $2 per GJ or less by 2028 onwards.

Figure 9: Forecast wholesale prices at the Wallumbilla Hub, all scenarios and Compared to the Cost of Production for Cooper Basin 2C plus Pipeline Tariff to Wallumbilla Hub – 2025 to 2045 ($Aus per GJ)



Sources: AEMO (2022; 2022c).

Only in relation to under the ***Progressive Change*** scenario is the delivery cost of 2C gas from the Cooper Basin sometimes either below or equal the projected wholesale gas price (10 out 21 years). In relation to all other scenarios, the delivery cost of 2C gas from the Cooper Basin is above the projected wholesale gas price. On this basis, one would conclude that no gas producer would choose to develop 2C gas resources in the Cooper Basin for the foreseeable future as it would be uneconomic to do so.

Only in relation to a ***Slow Change*** scenario that AEMO no longer sees fit to include as part of the 2022 GSOO, presumably because it no longer bears any resemblance to expected future outcomes and events, would the development of Cooper Basin 2C resources, including unconventional gas, become a viable proposition.

Wholesale gas prices within the Eastern Gas Region have dramatically increased since late March 2022 with increased demand triggered by the need for more GPG. Average weekly wholesale gas prices at the Wallumbilla Hub went from $10.40 per GJ in the week commencing 20 March, rising to $19.54 in the week commencing 1 May (Australian Energy Regulator, 2022). 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 (2022).

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.

However, the factors contributing to recent gas price rises both domestically and internationally are likely to abate in time and high prices are unlikely to be sustained. In the Eastern Gas Region, coal power generators are likely to come back online following maintenance and repairs as well as improvements in coal supply. Furthermore, 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). While the global LNG market is expected to be tight to be tight through to 2025, as demand growth is evenly matched by supply growth, from 2026 onwards several sizeable projects are expected to come online in both the U.S. and Qatar which is expected to result in the market being over-supplied (Department of Industry, Science, Energy and Resources, 2022, p. 79), in turn putting downward pressure of global LNG prices.

7. Carbon Dioxide Emissions From Unconventional Gas Production in the Lake Eyre Basin

7.1 Development of Emissions Scenarios

Methane is 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 per cent of global emissions. Methane is more than 25 times as potent as carbon dioxide at trapping heat in the atmosphere.

The GHGs that are reported under the National Greenhouse and Energy Reporting (NGER) Scheme include CO_2, methane (CH_2), nitrous oxide (N_2O), sulphur hexafluoride (SF_6) and specified kinds of hydro fluorocarbons and perfluorocarbons (Clean Energy Regulator, 2021).

Professor Ian Lowe (AO) (2022), an emeritus professor in the School of Environment and Science at Griffith University, has estimated the likely emissions from both CO_2 and carbon dioxide-equivalent (CO_2-e) in relation to the following scenarios for the production of unconventional gas in the LEB:

- Emissions for a low export gas scenario (400 PJ per year)
- Emissions for a high export gas scenario (2,000 PJ per year).

Professor Lowe (2022) assessed the likely emissions against the Queensland Government's emissions reduction targets to achieve net zero emissions by 2050 and a 2030 target of 133 megatonnes (Mt) CO2-e, around 31 Mt per year below the 2019 figure. According to Professor Lowe (2022):

> *The results are truly startling. They demonstrate that unconventional gas development in the Lake Eyre Basin would be totally incompatible with Queensland's stated 2030 emissions reduction target.*
>
> *…*
>
> *If this development were to go ahead, even at that more modest scale and using generous assumptions, meeting the Queensland target would require a clearly impossible scale of reduction in all other activities: electricity, transport, manufacturing, agriculture and domestic use.*

In the Net-Zero Emissions by 2050 Scenario (NZE) developed by the International Energy Agency (IEA) (2021, p. 175) in its roadmap for the global energy sector, no new oil and natural gas fields are required beyond those already approved for development, and supplies become increasingly concentrated in a small number of low-cost producers. On this basis, the development of any new commercial gas fields in the Georgina Basin would arguably put the Queensland Government in breach of its target for net zero emissions by 2050.

Given the scale of future development required in the Cooper-Eromanga basins under both the high and low export gas scenarios, the Queensland Government's commitment to net zero emissions by 2050 would also become problematic. Gas and ethane production from conventional sources in the

Cooper Basin peaked at just over 250 PJ per annum around 2000-2002 (Oakley Greenwood, 2017, p. 41).

The production of an additional 2,000 PJ per annum of unconventional gas under the high export gas scenario is probably unlikely as it would more than double current gas production in the Eastern Gas Region. Given the relatively small level of domestic gas demand across the Eastern Gas Region, this would require the construction of at least an additional 8 LNG trains (assuming the current LNG trains in the Eastern Gas Region already have access to sufficient gas to service their export contracts). With the massive cost blowouts associated with the construction of the most recent Australian LNG plants, it is highly unlikely we will see a level of investment on this scale in new LNG trains. There were cost blowouts conservatively estimated to be in the order of $45 billion in the construction of seven LNG plants around the country, including the three check-by-jowl LNG plants based in Gladstone (Macdonald-Smith, 2020). On this basis, further consideration of a high export scenario has been excluded from the analysis.

In the further development of a low export scenario, it will be assumed unconventional gas is sourced exclusively from the Cooper-Eromanga basins given the uncertainty surrounding the quantity of unconventional gas resources in the Georgina Basin.

7.2 Carbon Dioxide Content of Unconventional Gas in the Cooper Basin

Unconventional gas in the Cooper Basin have been shown to have a relatively high CO_2 content, ranging from around 21 per cent to almost 36 per cent (Lech, et al., 2020).

Rounding up a simple average of the CO_2 content from the various unconventional desorbed gas samples from across the Cooper Basin gives an average CO_2 content of 30 per cent. This compares to CO_2 content of around 3 per cent in shale gas extracted from the Beetaloo Sub-basin (Tamboran Resources, 2021, p. 6). The simple average of the methane content from the various unconventional desorbed gas samples from the Cooper Basin gives an average methane content of around 62 per cent.

7.3 Fugitive Emissions

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 (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).[13] GWPs are used to convert masses of different GHGs into a single carbon 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.

In the case of shale gas, the nature of the flowback of large volumes of hydraulic fracturing fluid containing high concentrations of liberated gas (owing to the high initial production rates of shale gas wells) leads to liberation of considerable amounts of fugitive methane gas (Cook, et al., 2013, p. 141).

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

[13] See Forster, et al., (2021, p. 1017). While Australia's National Greenhouse Gas Accounts (Department of Industry, Science, Energy and Resources, 2021, p. 65) uses GWP for methane 28 times that of CO_2, this is based on the Fifth Assessment Report (AR5) of the IPCC.

datasets recorded in published studies. No country directly monitors all fugitive emissions from the gas industry.

Air measurements at natural gas production sites indicate that a large proportion of fugitive emissions come from a small number of high-emitting sources (Pepper, et al., 2018, p. 216).

Past studies reporting divergent estimates of methane emissions from the natural gas supply chain have generated conflicting claims about the full GHG footprint of natural gas (Zavala-Araiza, et al., 2015). Top-down estimates based on large-scale atmospheric sampling often exceed bottom-up estimates based on source-based emission inventories.

One study that sought to reconcile top-down and bottom-up methane emissions estimates in one of the United States' major natural gas production basins found that gas methane emissions corresponded to 1.5 per cent of natural gas production (Zavala-Araiza, et al., 2015). 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 per cent of methane was emitted between extraction and delivery across the U.S. natural gas supply chain, including from both conventional and unconventional gas wells. This was based on the synthesis of methane emission data from a series of ground-based field measurements in a study undertaken by Zavala-Araiza, et al. (2015) that was integrated with a study conducted by Littlefield, et al. (2016).

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, assuming that fugitive emissions represent 1.7 per cent of total raw gas production on average does not appear to be unreasonable.

Taking a GWP for methane of 29.8 and assuming that fugitive emissions represent 1.7 per cent of total raw gas production for a low export gas scenario provides an estimate of fugitive emissions of 4.1 Mt of CO_2-e per annum.[14]

7.4 Natural Gas Processing Emissions and Carbon Capture and Storage

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 are 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.

A low export gas scenario provides an estimate of CO_2 emissions vented during the processing of natural gas of 3.9 Mt in order to produce 400 PJ of processed natural gas.[15]

However, these high emissions during the processing stage could be reduced through carbon capture and storage technology (CCS) (Cook, et al., 2013, p. 143).

CCS, sometimes referred to as carbon capture, utilisation and storage (CCUS), takes CO_2 captured from the burning of fossil fuels and other sources (such as from cement production, steel manufacture), and injects it deep underground into the tiny pore spaces present between grains in

[14] Figure has been rounded down to to 4.1 Mt, while the raw figure is 4.119 Mt rounded to three decimal places. It has been assumed that 400 PJ of processed natural gas is equivalent to 8 Mt, that the methane content of raw unprocessed unconventional gas is 62 per cent, and the CO_2 content is 30 per cent under a low export gas scenario. The fugitive emission estimate of 4.1 Mt of CO_2-e is compatible with the estimate of 5 Mt of CO_2-e. Professor Lowe used a GWP for methane of 33 and presumably rounded up an initial estimate of around 4.5 Mt of CO_2-e up to 5 Mt.

[15] Figure has been rounded up to 3.9 Mt, while the raw figure is 3.871 Mt rounded to three decimal places.

sedimentary rocks (such as sandstones) (Geoscience Australia, n.d.). Typically, depths of storage are around 2 km underground.

CO_2 is captured from stationary emissions sources such as power stations, natural gas production, fossil fuel hydrogen production and industrial facilities such as steel or cement manufacturing plants. CO_2 can be transported from the emission source to the storage location via pipelines, ships, by road (truck) or rail, much like natural gas (Geoscience Australia, n.d.). At the storage location, CO_2 is injected deep underground into a suitable geological formation for permanent storage, such as saline aquifers (e.g. sandstones that are filled with brine), depleted oil or gas fields, and potentially in other types of rocks such as deep coal seams or basalts. Within the reservoir rock, CO_2 is initially trapped within the pore spaces between grains and prevented from moving out of the formation by overlying impermeable rocks (seals). Over time, the CO_2 dissolves into the formation water, eventually reacting to form new minerals. Some of the captured CO2 can be used to make other products. For example, CO_2 may be injected underground to enhance oil recovery in mature oil fields or used to create new products, such as fertilisers, fuel or food products.

On 1 November 2021 Santos (2021) announced that it along with its joint venture partner in the Cooper Basin Beach Energy had taken a final investment decision to proceed with the US$165 million Moomba CCS project in SA, with start-up expected in 2024. Santos Managing Director and Chief Executive Officer Kevin Gallagher said the Moomba CCS project will be one of the biggest and lowest cost in the world and will safely and permanently store 1.7 Mt of CO_2 per year. Santos has forecast a full lifecycle cost of less than US$24 per tonne of CO_2 including cash costs in operation of US$6-8 per tonne of CO_2, with first injection targeted for 2024. On this basis, it is feasible that the venting CO_2 emissions from processing unconventional gas development in the Cooper Basin could be partially offset through CCS.

While CCS technology has been in operation for half a century, it has proven to be an unreliable technology in several cases (Robertson & Mousavian, 2022, p. 1). The majority of projects globally using CCS have had unique engineering challenges that have led to underperformance and cost blow-outs.

The Gorgon Gas Project, located on Barrow Island around 60 km off the northwest coast of WA and operated by Chevron, is one of the world's largest LNG projects (Chevron Australia, 2022). The first LNG cargo departed Barrow Island on 21 March 2016 and domestic gas supply to the Western Australian market commenced in December 2016.

As part of the Gorgon Gas Project, the Gorgon carbon dioxide injection project had plans to inject 3.3 to 4 Mt of CO_2 dioxide per year into the Dupuy Formation, a geological layer consisting of sandstone more than two kilometres beneath Barrow Island (Department of Mines, Industry Regulation and Safety, n.d.; Chevron Australia, 2021). The $3.1 billion program to inject CO_2 from the offshore Gorgon gas field underneath Barrow Island was a major plank of the $US54 billion Gorgon Gas Project and was the recipient of $60 million in funding from the Commonwealth Government (Milne, 2017; 2021).

Attempting to bury up to 4 Mt per annum of CO_2 a year under Barrow Island is not simple (Milne, 2021). CO_2 is injected into a layer of sandstone about 400 metres thick more than 2,000 metres underground, and about 4 km away water is pumped to the surface from the same layer to make room for the CO_2. This water is then pumped into a different layer of rock above the CO_2. If the water is not moved the pressure required to inject the CO_2 will rise and reduce the amount of CO_2 that can be stored, and eventually risk fracturing the rock around the CO_2 injection wells.

It was originally intended for the Gorgon carbon dioxide injection project to commence operations in 2016 (Carbon Capture and Sequestration Technologies program at MIT, 2016), however, it didn’t commence injecting CO_2 until early August 2019 (Department of Mines, Industry Regulation and Safety, n.d.).

CO_2 injection started more than three years after Gorgon first produced LNG because water entering the pipeline that injected CO_2 underground corroded pipework, creating a corrosion risk (Milne, 2021; Smyth & Sheppard, 2021). In turn, equipment replacement delayed the facility’s operations until August 2019 (Smyth & Sheppard, 2021). That problem caused an additional 7 Mt of CO_2 to be vented to the atmosphere (Milne, 2021).

In July 2021 Chevron blamed technical challenges for the three-year delay in commencing CCS operations (Smyth & Sheppard, 2021). It is reported that the Gorgon carbon dioxide injection project has only managed to store 6 Mt of CO_2 since it commenced operations (Milne, 2022).

Another problem faced by the Gorgon carbon dioxide injection project is that sand has also clogged an underground reservoir designed to fill with displaced water when CO_2 is pumped underground (Smyth & Sheppard, 2021). The sand was a known risk, and Chevron targeted its water extraction at depths thought not to have weak zones prone to sand production (Milne, 2021). Australian regulators have since cut the injection rates since December 2020 on safety grounds (Smyth & Sheppard, 2021).

The WA Department of Mines, Industry Regulation and Safety (DMIRS) allowed Chevron to begin injecting CO_2 in August 2019 without the so-called the pressure management system, provided it started operating by December 2019 (Milne, 2021). In December 2019 DMIRS granted an extension to May 2020 and at that milestone the project was given another seven months to December 2020. DMIRS then granted Chevron a further six months to June 2021 to fix the pressure management system, but this time it capped the level of CO_2 injection and increased reporting requirements.

Chevron Australia's director of operations, Kory Judd, commented in May 2022 the CCS project was operating at only half of its designed capacity and that the company did not have a timeframe for when it would be able to meet its CO_2 capture targets (Newsbase Daily News, 2022). According to Judd:

> *We've still got a way to go to meet the commitment to what we have the injection system designed for. What we're doing is trying to learn our way through how you inject CO_2 into the reservoirs, how do they respond, then how do you do that reliably and how do you do that and get to the point to meeting the commitments that you've got.*

Chevron and its partners were required to capture a minimum of 80 per cent of the emissions from the Gorgon Gas Project as a condition of the project's approval (Newsbase Daily News, 2022). The shortfall from the target level for the period 18 July 2016 and 17 July 2021 is 5.23 Mt of CO_2-e (Chevron, 2021, p. 45). Chevron has committed to acquiring and surrendering GHG emission offsets to offset this shortfall.

Bruce Robertson and Milad Mousavian (2022, p. 11) from the Institute for Energy Economics and Financial Analysis have pondered in relation to the Gorgon carbon dioxide injection project:

> *The extent of the technical failure of Gorgon CCS cannot be overstated. It prompts the question: if the engineers from the project backers – the super major oil companies Chevron, Shell and Exxon – cannot get CCS to work as forecast, who can?*

Similarly, Channel 9 newspapers business reporter Peter Milne (2022) has mused:

> *The conundrum of CCS is that it has a patchy record of performance to date but still features as an essential part of most scenarios to achieve net-zero emissions by 2050.*

7.5 Cost of Offsetting Fugitive Emissions and Natural Gas Processing Emissions

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).

As a low export gas scenario for the production of unconventional gas in the Cooper Basin will be emitting around 8.0 Mt of CO_2-e emissions per annum, it will need to be covered by the safeguard mechanism. As the newly elected Albanese Commonwealth Government has committed to reducing emission baselines under the safeguard mechanism predictably and gradually over time (Australian Labor Party, 2021), and in light of pre-existing conventional oil and gas production in the Cooper Basin, it is highly likely that all emissions under a low export scenario for unconventional gas will need to be offset.

ACCUs were trading around $35.25 a tonne on the spot during June 2022, only slightly above the cost ceiling for CCS at Moomba nominated by Santos (taking into account the prevailing exchange rate).[16] This in turn suggests that the cost of offsetting emissions through the purchase of ACCUs will be roughly equal to the cost of offsetting emissions through CCS.

The estimated cost of offsetting 4.1 Mt of CO_2-e from fugitive emissions for a low export gas scenario for the production of unconventional gas based on the current price of ACCUs would be $145.2.8 million per annum, adding $0.36 per GJ to the cost of gas. The estimated cost of offsetting 3.9 Mt of CO_2 emissions from venting during processing would be $136.5 million per annum, adding $0.34 per GJ to the cost of gas. In turn, the total cost of offsetting fugitive emissions and emissions from venting during processing of 8.0 Mt of CO_2-e would be $281.6 million per annum, adding $0.70 per GJ to the cost of gas.

While other gas fields may also have to deal the cost of offsetting fugitive emissions, the high CO_2 content of unconventional gas from the Cooper Basin puts it at a distinct competitive disadvantage compared to other gas fields where the CO_2 content of the raw gas is much lower. For example, a low export gas scenario producing 400 PJ of processed natural gas from the Beetaloo Sub-basin with an assumed raw gas content of 77 per cent methane and a reported 3 per cent CO_2 content would generate similar levels of fugitive emissions to a low export gas scenario in the Cooper Basin, however, it would generate only 0.3 Mt of CO_2 emissions from venting during gas processing as compared to 3.9 Mt.[17] While the cost for offsetting fugitive emissions would be similar, the cost of offsetting 0.3 Mt of CO_2 emissions from venting during processing would be only around $11 million, adding only $0.03 per GJ to the cost of gas.

8. Conclusions

In its roadmap for the global energy sector to reach NZE by 2050, the IEA (2021, p. 175) has suggested that nearly all LNG exports in 2050 will come from the lowest cost and lowest emissions producers. However, the available evidence suggests unconventional gas produced from the Cooper Basin in the Lake Eyre Basin will be neither low cost nor low emissions. Furthermore, any requirement to offset emissions from the production of unconventional gas will further erode its competitiveness given the high CO_2 content of raw gas.

Rather than pose the risk of becoming stranded assets, the commercial production of unconventional gas from the Lake Eyre Basin would be the absolute height of folly if it were ever to be commenced.

[16] Santos (2021) suggested the cost of CCS at Moomba would be less than US$24 per tonne of CO_2, that comes to less than $34.75 per tones in Australian dollars at the prevailing exchange as of 16 June 2022.
[17]

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