



# REPORT ON THE NARRABRI GAS PROJECT

Dr Alistair Davey | Roger Fisher | August 2019



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

For information on this report please contact:

**Name:** Dr Alistair Davey

**Telephone:** + 61 2 6100 4090

**Mobile:** 0422 211 110

**Email:** [adavey@pegasus-economics.com.au](mailto:adavey@pegasus-economics.com.au)

*Photograph on the front cover is a coal seam gas well and flare in the Pilliga forest*

# REPORT ON THE NARRABRI GAS PROJECT



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# EXECUTIVE SUMMARY

## NARRABRI GAS PROJECT

- ▲ Santos applied to the NSW Department of Planning and Environment in 2017 to develop the Narrabri Gas Project (Australian Energy Regulator, 2018a, p. 188). The Narrabri Gas Project involves the extraction of natural gas resources from coal seam gas (CSG) in the Gunnedah Basin about 20 km south-west of the town of Narrabri (GHD, 2017, p. 1.1).

## EASTERN GAS REGION

- ▲ 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). In turn, the Eastern Gas Region had a balanced gas market whereby 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).
- ▲ The development of the three liquid natural gas (LNG) export projects in Queensland transformed the Eastern Gas Region, giving producers a choice between exporting their gas or selling it domestically (Australian Energy Regulator, 2018a, p. 182).
- ▲ Consumption of natural gas from the LNG export projects now dwarfs that for domestic users (Bethune & Wilkinson, 2019, p. 520).
- ▲ While a majority of Eastern Gas Region's gas reserves are located in the Surat and Bowen Basins in Queensland, those reserves are largely committed to the LNG export industry (Australian Energy Regulator, 2018a, p. 201).
- ▲ The supply of natural gas in the Eastern Gas Region has tightened since the Queensland LNG export projects started to draw on reserves from the Eastern Gas Region (Australian Energy Regulator, 2017, p. 8).
- ▲ Decisions made by one of the Queensland LNG export projects stand out as the root cause of future impending natural gas shortfalls in the Eastern Gas Region. In late October 2010 Santos (2010) announced that it had reached an agreement to supply 750 petajoules (PJ) of gas to the Santos-led Gladstone Liquid Natural Gas (GLNG) project, with existing uncontracted Cooper Basin gas reserves being the primary supply source.

*Jim Snow (2017), Executive Director of energy consultants Oakley Greenwood, has described this agreement as the "smoking gun" for impending natural gas shortfalls in the Eastern Gas Region.*

The Santos-led GLNG project has diverted natural gas from domestic users to export markets as it has not exclusively relied upon newly developed CSG fields to fulfil its export contracts, and it has been the major contributor towards any impending natural gas shortfalls within the Eastern Gas Region.

## NARRABRI GAS PROJECT IN THE CONTEXT OF NSW GAS SUPPLY

- ▲ NSW is currently heavily dependent on imports from other states for its gas supplies.
- ▲ The gas fields that have traditionally supplied the NSW market, primarily the Gippsland Basin in Victoria and the Cooper Basin in South Australia and Queensland, are in natural decline. Furthermore, most of the remaining future gas reserves in the Cooper Basin have been contracted to GLNG.



- ▲ In addition, CSG reserves developed by LNG export projects in Queensland are not sufficient to supply the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).
- ▲ Under these circumstances, the development of the Narrabri Gas Project would provide additional gas supply for NSW. However, based on current estimates, the Narrabri Gas Project will not provide a complete solution to any impending gas shortfalls in NSW as it will still need to find additional sources of supply.
- ▲ This Narrabri Gas Project is a relatively high cost gas development project with an estimated production cost of \$7.40 per gigajoule (GJ), ranking 41 out of 51 actual and undeveloped gas projects according to the Australian Energy Market Operator (AEMO) (2019).
- ▲ There are 18 developed and 22 undeveloped gas projects with lower estimated production costs than the Narrabri Gas Project.
- ▲ The available evidence suggests that gas produced from the Narrabri Gas Project will be far too expensive to be of any interest for the LNG export projects and thus Santos' claims that gas produced from Narrabri will be directed towards domestic gas users appears credible.

## GAS PRICING IN THE EASTERN GAS REGION

- ▲ With the commencement of LNG exports in early 2015, the Eastern Gas Region was transformed from a captive domestic "buyer's" market to an internationally-linked "seller's" market (Forcey & McConnell, 2017, p. 12). In turn, the development of the three LNG export projects in Queensland exposed domestic gas users to international gas prices for the first time (Australian Competition and Consumer Commission, 2016, p. 22).
- ▲ Any competitive tensions in the supply of gas for the Eastern Gas Region that may have previously existed would have evaporated when Santos decided to prioritise and redirect the bulk of its Cooper Basin gas production to GLNG and LNG export markets.
- ▲ There has been a subsequent rapid increase in wholesale gas prices from historical values of around \$3 per GJ to present prices of around \$10 per GJ since the three LNG export projects commenced operations in 2015 and Santos prioritised Cooper Basin production to GLNG.

## CAN THE NARRABRI GAS PROJECT LOWER GAS PRICES?

- ▲ Claims have previously been made that developing NSW's CSG resources would put downward pressure on gas prices. In turn, this would have flow on effects for the cost of gas powered generation (GPG) leading to lower electricity prices.
- ▲ However, the NSW Independent Pricing and Regulatory Tribunal (IPART) has expressed a contrary view. According to IPART (2014, p. 2), the development of the three LNG export projects means the Eastern Gas Region has become linked to global LNG markets with prices and that, as a consequence, NSW prices would adjust to world prices.
- ▲ In turn, IPART (2015, p. 2) has expressed scepticism as to whether the development of CSG projects in NSW is likely to have a bearing at all on gas prices in NSW.
- ▲ According to the current Chair of the ACCC, Mr Rod Sims (2019):

*The level of future domestic prices in the southern states will depend on the marginal source of supply in the southern states.*

- ▲ The role of the marginal source of supply in setting wholesale prices has been described in the following terms:

*In a competitive market wholesale prices are based on the cost of the marginal source of supply. This is the final source of gas or electricity supply needed to meet demand. What makes up the marginal source of supply will vary depending on what supplies are available, the costs of those supplies, and the level of demand. (Ofgem, 2016, p. 12)*

- ▲ The available evidence suggests the Narrabri Gas Project is never likely to become the marginal source of supply either in the short term or over the longer term, and is thus unlikely to influence, let alone reduce gas prices.
- ▲ Based on analysis by energy consultants the Core Energy Group, the ACCC (2018, p. 82) has found the marginal source of supply in the Eastern Gas Region in the short term to be gas from the Surat Basin with a forward production cost of \$5.55 per GJ.
  - The marginal source of supply plus the current published transmission costs from the Wallumbilla Gas Supply Hub in Queensland to Sydney of \$2 per GJ (APA Group, 2019a), provides a delivered cost of gas to Sydney of \$7.55 per GJ compared to a delivered cost to Sydney of \$9 to \$9.40 per GJ from the Narrabri Gas Project.
- ▲ In the face declining gas production in the southern states and the possibility of restricted gas supply from Queensland due to limited available CSG production and pipeline infrastructure constraints, there are currently proposals for the construction of five LNG import terminals in the southern states.
- ▲ There are a number of reasons why LNG imports might be competitive with pipeline imports from Queensland (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 100).
  - First, the cost of production in Queensland is relatively high.
  - Second, transporting gas via pipeline from Queensland to the southern states is relatively costly.
- ▲ If imported gas, namely LNG, becomes the marginal source of supply over the longer term, then wholesale gas prices will be set to import parity levels in order to attract the supply of gas required to meet demand.
- ▲ It is highly unlikely the development of the Narrabri Gas Project will do anything ease electricity prices in the National Electricity Market.
- ▲ The Narrabri Gas Project is unlikely to ease cost pressures from higher gas prices facing manufacturers.

## CONCLUSIONS

- ▲ Santos and the Santos-led GLNG project have been significant contributors toward any impending gas shortfalls in the Eastern Gas Region as GLNG did not possess sufficient gas resources to justify its investment decision for a second LNG train. In turn, they have diverted substantial volumes of gas from domestic users through third-party gas supply contracts to satisfy their export contracts, contrary to previous claims that it would not.
- ▲ Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its Narrabri Gas Project, without acknowledging the central role it played in creating the circumstances that it claims the Narrabri Gas Project will help to alleviate.
- ▲ While the development of the Narrabri Gas Project will provide additional gas supply for NSW, there are plenty of cheaper gas resources that could be developed, and it is unlikely to have any bearing over gas prices either in the immediate future or over the longer term.





# 1. INTRODUCTION

The Wilderness Society has commissioned Pegasus Economics to analyse the potential impact of the proposed Narrabri Gas Project upon east coast gas prices and the availability of gas on the Australian east coast. The views and opinions expressed in this report are entirely those of the authors.

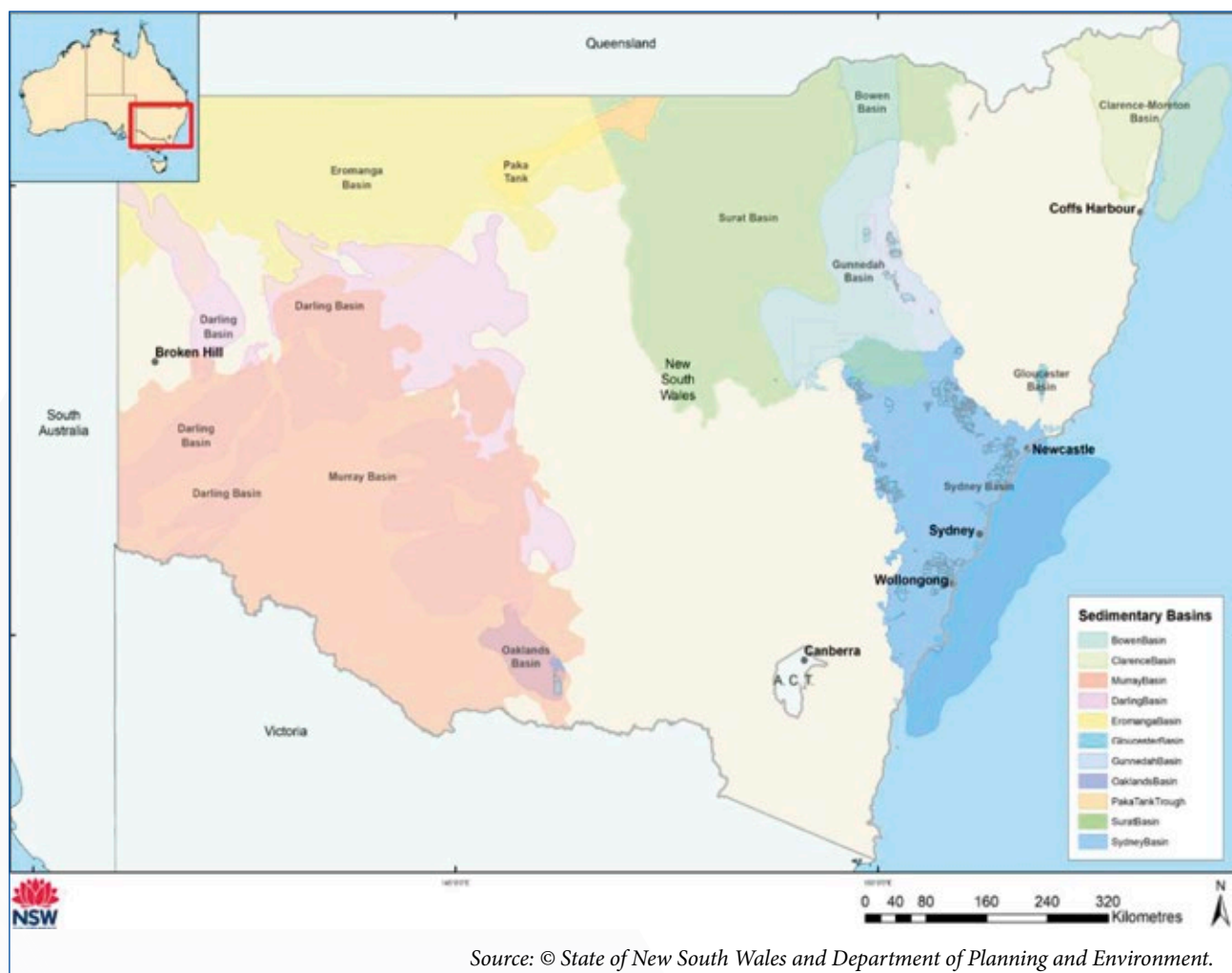
## 2. NARRABRI GAS PROJECT

### 2.1 Gunnedah Basin

The Gunnedah Basin is a structural trough in northeast New South Wales (NSW) (O’Kane, 2013, p. 43). The basin appears continuous with the Bowen Basin in the north and the Sydney Basin in the south. The Great Artesian Basin overlies the Gunnedah Basin. The Gunnedah Basin occupies an area of 15,000 km<sup>2</sup> (Upstream Petroleum Consulting Services, 2000, p. 7).

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

Figure 1: New South Wales Sedimentary Basins



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

## 2.2 Background to the Narrabri Gas Project

The Narrabri Gas Project proposes to extract natural gas resources from coal seam gas (CSG) in the Gunnedah Basin about 20 km south-west of the town of Narrabri (GHD, 2017, p. 1.1).

The Narrabri Gas Project has been proposed by Santos NSW (Eastern) Pty Ltd, a wholly owned subsidiary of Santos Ltd (Santos), an Australian oil and gas company listed on the Australian Securities Exchange. Santos will operate the project on behalf of its joint venture participants (GHD, 2017, p. 1.1).

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

The project area contains a portion of the Pilliga Forest with the majority of the project located on Crown land (GHD, 2017, p. 1.1). The Pilliga Forest is an agglomeration of forested areas covering more than 500,000 hectares around Coonabarabran, Baradine and Narrabri.

Santos (2017c) states that it is intending to make the gas extracted by the Narrabri Gas Project available to NSW via a pipeline linking into the existing Moomba to Sydney Pipeline.

Santos (2011b) first acquired interests in the Gunnedah Basin in 2007. In June 2008 Santos (2008) entered into agreements with project partners to explore for CSG in the Gunnedah Basin.

In July 2009 Santos (2009) acquired significant additional acreage in the Gunnedah Basin and an investment in a local CSG company, Eastern Star Gas Limited (ESG). As part of this transaction, Santos acquired:

- ▲ Gastar Exploration Limited's 35 per cent interest in various Gunnedah Basin exploration permits and production areas operated by ESG
- ▲ 20 per cent interest in ESG.

In July 2011 Santos (2011b) entered into an agreement to acquire 100 per cent of ESG and to sell a 20 per cent working level interest in ESG's permits in the Gunnedah Basin to EnergyAustralia (formerly TRUenergy).

ESG (2001; 2001a) was listed on the Australian Stock Exchange in February 2001 with interests in three petroleum exploration licences in the Gunnedah Basin, with applications pending on another two that were subsequently granted. ESG (2010, p. 10) developed the gas fired electricity generating Wilga Park Power Station located to the west of Narrabri (Eastern Star Gas Limited, 2010). The Wilga Park Power Station was originally constructed and operated pursuant to a development consent granted by Narrabri Shire Council on 14 November 2002.

The Wilga Park Power Station was connected to the National Electricity Market through its connection to the electricity grid in July 2004 (Wragg, 2004). The Wilga Park Power Station was originally supplied with gas produced from the conventional Coonarah Gas Field, but when this field failed to live up to production expectations, it was closed down (Eastern Star Gas Limited, 2010, p. 10). Following the installation of pipeline infrastructure, the Wilga Park Power Station was instead supplied with gas from CSG fields at Bibblewindi and Bohena (Eastern Star Gas Limited, 2010, p. 28).

Small amounts of CSG are currently being generated from Narrabri Gas Project exploration wells to supply gas to the Wilga Park Power Station (General Purpose Standing Committee No. 5., 2012, p. 11) to provide electricity for the equivalent of about 23,000 households in northwest NSW (Santos Ltd, 2019b).

In July 2012 the NSW Environment Protection Authority (EPA) (2012) issued ESG with two penalties and fines of \$3,000 for discharging polluted water to Bohena Creek in the Pilliga Forest. In February 2014 the EPA (2014) issued a \$1,500 fine to Santos NSW (Eastern) Pty Ltd following a pollution incident at their Narrabri Gas Field operations in the Pilliga. In May 2015 the EPA (2015a) completed investigations into two separate incidents that occurred at the Narrabri Gas Project in 2013 and 2015. Although the investigations showed that neither of these

incidents resulted in any significant environment impacts, the EPA did express concerns with aspects of the site operations and management.

In its 2014 investor seminar, Santos (2014, p. 66) announced that its proven and probable gas reserves in the Gunnedah Basin were likely to be 30 per cent lower than its year-end estimates in 2013. On 12 February 2015 Santos (2015a) announced an impairment charge of \$808 million before tax on the Narrabri Gas Project following the downgrading of its proven and probable gas reserves in the Gunnedah Basin.

Similarly, in February 2015, CLP Holdings (2015, p. 72), the Hong Kong based parent company of EnergyAustralia, also announced an impairment provision for the Narrabri Gas Project:

*In 2014, an impairment provision of HK\$1,578 million (A\$248 million) was made on the Narrabri Coal Seam Gas Project, in which EnergyAustralia holds a 20% interest. The provision was made based on additional drilling data and analysis that reflected a reduction in the estimated total gas reserves and a fall in estimated daily production.*

In February 2016 Santos (2016a) reclassified its proven and probable reserve in the Gunnedah Basin as contingent resources. Also in February 2016 Santos (2016, p. 61) booked another impairment charge of \$588 million on the Narrabri Gas Project, writing down the book value of the project to zero.

In December 2016 Santos (2016b) relegated the Narrabri Gas Project to the status of a “non-core asset” which would be run as a standalone business. Santos’ announced policy in relation to its non-core assets was to optimise value through sweating or exiting the assets.

At its 2017 Investor Day in November 2017, Santos (2017b) announced the Narrabri Gas Project would re-join the company’s core asset portfolio. Despite this, the value of Santos’ assets in the Gunnedah Basin are still listed as zero on its balance sheet.<sup>1</sup>

## 2.3 Approval Process

In February 2014 the NSW Government signed a Memorandum of Understanding (MoU) with Santos for the proposed Narrabri Gas Project (Stoner & Roberts, 2014). The MoU sought to ensure the assessment of the project was progressed in a timely manner and that Santos (2014a) met industry best practice in relation to key environmental safeguards.

Santos and its project partner EnergyAustralia applied to the NSW Department of Planning & Environment on 14 May 2014 for a Petroleum Production Lease that is still under consideration. A Petroleum Production Lease gives the holder the exclusive right to extract petroleum within the production lease area during the term of the lease (NSW Government Department of Planning & Environment, n.d.). Development consent under the *Environmental Planning and Assessment Act 1979* (NSW) must be in place before a Petroleum Production Lease can be granted.

However, Santos missed a key deadline in its MoU with the NSW Government to fast-track a development decision on the Narrabri Gas Project (Lloyd, 2014). Under the terms of the MoU, Santos was due to lodge an environmental impact statement (EIS) for the Narrabri Gas Project by 30 June 2014. In return, the NSW Government agreed to make a decision on whether or not to approve the development by 23 January 2015.

An EIS for the Narrabri Gas Project was submitted in February 2017. The Narrabri Gas Project is currently being assessed by the NSW Department of Planning & Environment ahead of an expected reference to the NSW Independent Planning Commission. According to Santos, 98 per cent of the 23,007 submissions received in response to the EIS objected to the project, with 1 per cent in support and another 1 per cent neutral (Macdonald-Smith, 2018).

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<sup>1</sup> See Santos (2019, p. 85).

In late May 2019 Santos Managing Director and Chief Executive Officer Kevin Gallagher commented to *The Australian* newspaper in relation to the Narrabri Gas Project that:

*I was really pleased to see the Premier in Queensland requesting a timeline for Adani to get a decision and I think that's what's been lacking for us as well.*

*We would welcome a timeline being set so we know what we're dealing with. (Williams, 2019)*

In late June 2019 NSW Deputy Premier and Resources Minister John Barilaro commented on Santos in relation to the approval process for the Narrabri Gas Project:

*They have dragged their heels and have no one else to blame but themselves. Proper decisions are based on proper processes and I won't be pushed around by Santos. (Hannam, 2019)*

In late July 2019 Mr Gallagher (2019, pp. 5-6) said in a speech to the Petroleum Club of Western Australia:

*In New South Wales, momentum is finally behind our Narrabri Gas Project and I am hopeful of a planning decision by the end of 2019 so that we can move forward with this project next year.*

## 3. NATURAL GAS

### 3.1 Natural Gas Deposits

Natural gas comprises gases occurring in deposits, whether liquefied or gaseous, consisting primarily of methane (International Energy Agency, 2018, p. 1.3). Methane is a hydrocarbon which are chemical compounds consisting of only hydrogen and carbon atoms. Methane is composed of one carbon atom surrounded by four hydrogen atoms.

Natural gas commonly exists in mixtures with other hydrocarbons, principally ethane, propane, butane, and pentanes, also known as 'natural gas liquids' (NGLs) (Naturalgas.org, 2013). In addition, raw natural gas contains water vapour, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds.

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 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.

Natural gas is sometimes found in sedimentary basins. 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, 2018). These layers are buried under sand, silt, and rock, and with subsequent pressure and heat changes some of this carbon and hydrogen-rich material turns into coal, some into crude oil, and some into natural gas.

In some places, natural gas moved into large cracks and spaces between layers of overlying rock (U.S. Energy Information Administration, 2018). The natural gas found in these types of formations is referred to as conventional natural gas. In other places, natural gas occurs in the tiny pores (spaces) within some formations of coal, shale, sandstone, and other types of sedimentary rock. This natural gas is referred to as unconventional natural gas.

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

There are several types of unconventional gas, including shale gas and tight gas, which occur in reservoirs that have very low permeability compared to conventional reservoirs (NSW Environment Protection Authority, 2015, p. 1). Shale gas is mainly methane trapped within shale rock layers at depths greater than about 1,500 metres (CSIRO, 2019). Tight gas refers to natural gas resources that are sealed in extremely impermeable, hard rock, making the underground formation extremely 'tight' and difficult to access (Rajput & Thakur, 2016).

Coal seam gas (CSG) is a form of natural gas, typically extracted from coal seams at depths of 300-1000 metres (CSIRO, 2019). It is mostly made up of methane.

### 3.2 Natural Gas Production

A production well is used to extract gas from subsurface deposits and 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, 2018). In conventional natural gas deposits, the natural gas generally flows easily up through vertical production wells to the surface.

In shale gas and tight gas geological formations, horizontal drilling and hydraulic fracturing or fracking are often necessary for economic gas extraction (NSW Environment Protection Authority, 2015, p. 1). Horizontal drilling involves the production well changing from a vertical to a horizontal direction underground (Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, 2017, p. 6). 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 Unconventional 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.

To extract CSG, a steel-encased well is drilled vertically into the coal seam at which point the well may also be hydraulically fractured or drilled horizontally along the coal seam to increase access to the gas reserves (NSW Environment Protection Authority, 2015, p. 2). The extraction of CSG does not always require hydraulic fracturing, but does require the removal of water from the coal to unlock the gas (dewatering) (Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, 2017, p. 5). Large amounts of salty water (brine) is produced and must be treated.

Once the gas is extracted from the wellhead, it is sent to processing plants (U.S. Energy Information Administration, 2018). Natural gas processing consists of separating all of the various hydrocarbons and fluids from the natural gas (Naturalgas.org, 2013). 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).

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 perceived concerns about the impact it may have on water resources and public health, and the potential for wells and associated infrastructure to impact upon farmland and rural communities.



### 3.3 Applications of Natural Gas and the Domestic Supply Chain

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 to its high hydrogen/carbon ratio, efficient combustion, and lower amounts of contaminants in the exhausted gases, including lower carbon dioxide emissions.

Natural gas has a wide range of applications including as a feedstock for gas powered electricity generators, and as a power source for appliances such as gas heaters, gas water heaters and gas stoves. Natural gas for electricity generation is the natural complement for renewable energy due to its lower carbon dioxide emissions and reliability as an energy source capable of being switched up and down quickly to deal with peaking demand and the intermittency of wind and solar power electricity generation (Gallagher, 2018, p. 6). 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).

Natural gas is also an important input in many industrial processes, including for the production of pulp and paper, metals, chemicals, stone, clay, glass and processed foods (Australian Energy Regulator, 2018a, p. 183). It is also a major feedstock in ammonia production for fertilisers and explosives.

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 business 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.

### 3.4 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), such as from Australia to countries in Asia. 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 to 1/630<sup>th</sup> of its original volume, and feeds into cooling coils that 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.

LNG tankers (or transport ships) rely on insulation to prevent the gas from reliquefying during transit (Stopford, 2009, p. 486). While the tanks on an LNG tanker are designed to stay cool, they cannot provide perfect insulation against warming (Fluenta, 2018). Heat slowly affects the tanks, which can cause the LNG inside to evaporate and produces a substance known as boil-off gas (BOG). When boil-off occurs and the methane returns to gas, the larger volume of gas will increase the tank pressure. To relieve the pressure in LNG tanks, BOG can be re-liquefied, used as fuel in the ship's engines or burned in a gasification unit.



At its destination, a regasification plant turns the LNG back into natural gas, and feeds it into a power utility or the local pipeline system (Stopford, 2009, p. 487). All this equipment makes the LNG trade very capital-intensive.

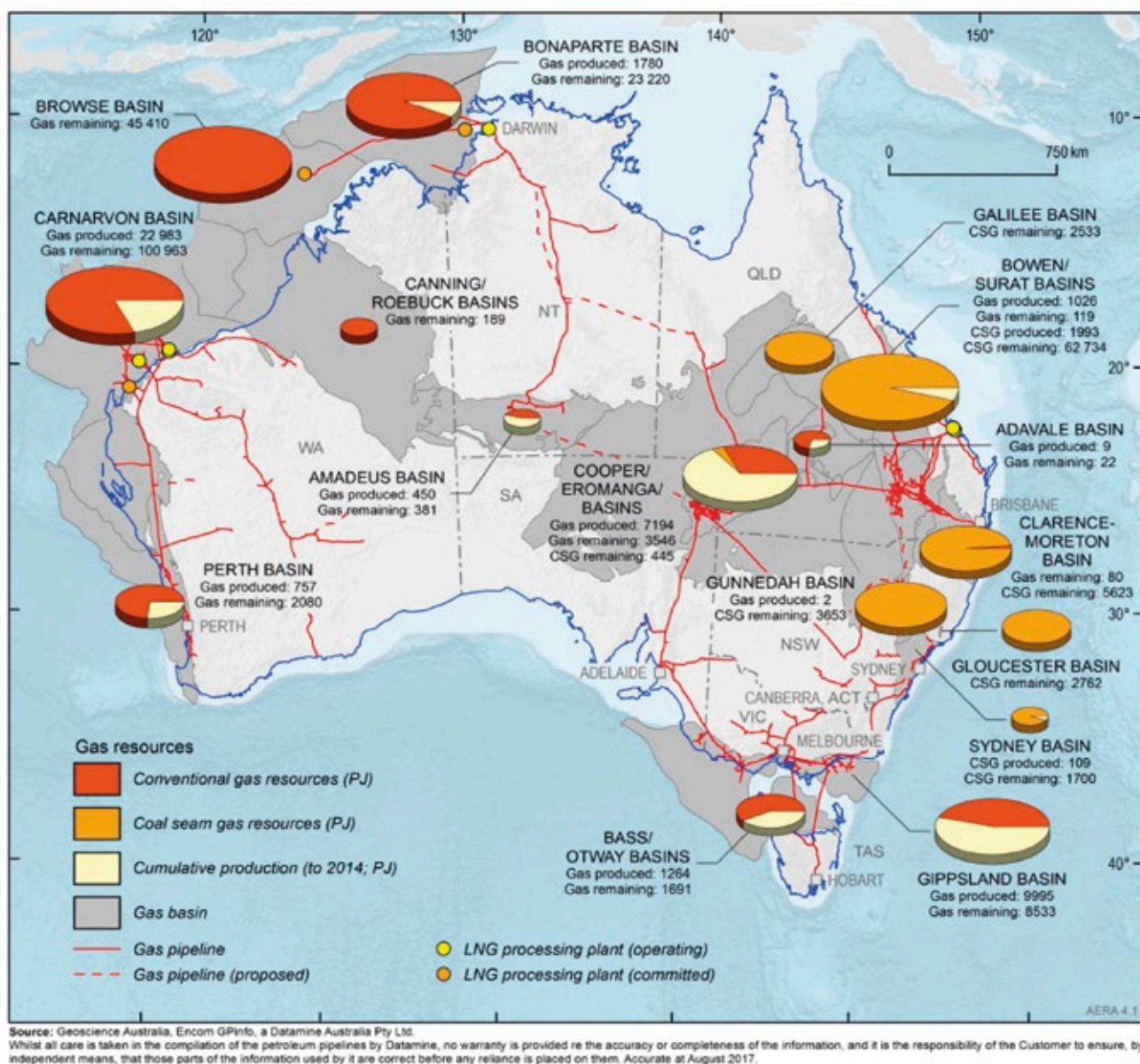
## 4. AUSTRALIAN NATURAL GAS RESERVES, DOMESTIC PRODUCTION AND EXPORTS

### 4.1 Australian Natural Gas Resources

Reserves are those quantities of natural gas anticipated to be commercially recoverable by a project to known accumulations from a given date forward (Society of Petroleum Engineers, 2017, 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 where there is a 50 per cent probability that the actual quantities recovered will exceed the estimate (Society of Petroleum Engineers, 2017, p. 13).

Reported at the 2P level, Australia has substantial gas resources including conventional and unconventional (including CSG, shale gas and tight) gas resources (Geosciences Australia, 2018). Australia's identified conventional gas resources have grown substantially since discovery of the supergiant gas fields on the North West Shelf north-west of Western Australia in the early 1970s. Gas resources have increased more than fivefold during the past 40 years. Australia's remaining gas reserves and cumulative production to 2014 is outlined in Figure 2 below.

Figure 2: Australia's remaining gas reserves and cumulative production to 2014 – Petajoules (PJ)



Natural gas can also be reported as contingent resources 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, 2017, p. 4). Contingent resources are commonly reported on a 2C basis, which refers to the best estimate of contingent resources (Society of Petroleum Engineers, 2017, p. 38).

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, 2017, p. 4). Prospective resources are commonly reported on a 2U basis, which refers to the unrisked best estimate qualifying as prospective resources.

Most of the conventional gas resources in Australia (approximately 95 per cent) are found in the Carnarvon, Browse, Bonaparte and Gippsland basins off the north-west and south-east coasts of Australia (Geosciences Australia, 2018). These resources have been progressively developed for domestic use and liquefied natural gas (LNG) export over the last five decades.

Australia also has significant unconventional gas resource potential, including CSG, shale gas and tight gas, in many onshore basins (Geosciences Australia, 2018). Significant CSG resources identified in the major coal basins of eastern Australia are being developed for LNG export and domestic use.

Australia's total identified gas resources are approximately 279,685 petajoules (PJ) (consisting of both reserves and contingent resources), which is sufficient to enable expansion of Australia's domestic and export production capacity (Geosciences Australia, 2018).<sup>2</sup> These resources are equal to approximately 106 years of gas at current production rates, of which the gas reserves account for 47 years. This is outlined in Table 1 below.

*Table 1: Australia's Identified and Prospective Gas Resources in 2014*

Resource category	Conventional gas	Coal seam gas	Tight gas	Shale gas	Total gas
	PJ	PJ	PJ	PJ	PJ
<b>Reserves</b>	77,253	45,895	39	0	123,187
<b>Contingent resources</b>	108,982	33,555	1,709	12,252	156,498
<b>All identified resources</b>	186,235	79,450	1,748	12,252	279,685
<b>Prospective resources</b>	235,913	6,890	2,650,622	9,577,353	12,470,778

*Source: Geosciences Australia (2018).*

At the end of 2014, Australia's total identified conventional gas resources were estimated at 186,235 PJ (Geosciences Australia, 2018). At current production rates, there are sufficient gas reserves (77,253 PJ) of conventional gas to last another 34 years.

In 2014, the CSG reserves in Australia were 45,895 PJ and accounted for approximately 38 per cent of the total gas reserves (Geosciences Australia, 2018). Reserve life is approximately 130 years at current rates of CSG production. More than 93 per cent of the reported CSG reserves are in Queensland, with the remainder located in NSW. In addition to reserves, Australia has substantial contingent resources (33,555 PJ) of CSG.

According to Geosciences Australia (2018), additional conventional gas resources are very likely to be found in Australia and there is also significant potential for additional unconventional gas resources, including CSG, shale gas and tight gas.

#### 4.1.1 Gas Resources in the Gunnedah Basin

There are different estimates of the quantity of available natural gas resources in the Gunnedah Basin, with differing estimates being provided by Geosciences Australia, the Australian Energy Market Operator (AEMO) and Santos.

According to Geosciences Australia (2018), the Gunnedah Basin contains proven and probable reserves (2P) of natural gas of 1,520 PJ and contingent resources (2C) of 2,133 PJ. On the other hand, the AEMO (2019) reports contingent resources (2C) of 971 PJ and prospective resources (2U) of 3,502 PJ. As discussed above, in February 2016 Santos (2016a) reclassified its proven and probable (2P) reserves in the Gunnedah Basin as contingent resources and hasn't provided an update since. Grossing up the Santos share of the Narrabri Gas Project to account for the entire project provides an estimate of contingent resources in the Gunnedah Basin consistent with the level of 2C resources reported by the AEMO.

The various gas resource estimates for the Gunnedah Basin are provided below in Table 2.

<sup>2</sup> A petajoule is a unit of energy used for expressing the energy content of fuels.

Table 2: Estimates of Gas Resources in the Gunnedah Basin (PJ)

Resource category	Geosciences Australia	Australian Energy Market Operator	Narrabri Gas Project*
	PJ	PJ	
Reserves	1,520		
Contingent resources	2,133	971	971
Prospective resources	3,653	3,502	

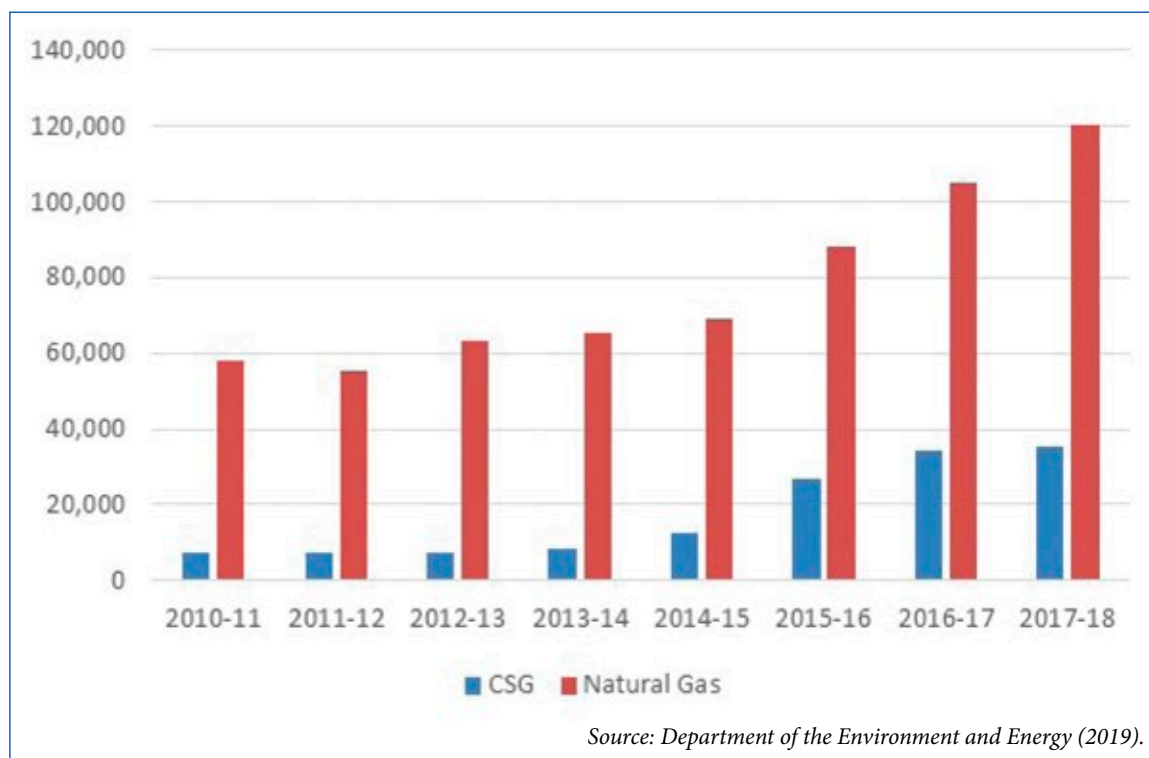
Sources: Geosciences Australia (2018), AEMO (2019) and Santos (2015; 2016a).

\* The Santos share of reported gas reserves in the Gunnedah Basin that were reclassified as contingent resources were grossed up to account for the entire Narrabri Gas Project.

## 4.2 Australian Natural Gas Production

Since 2010-11 Australian natural gas production has doubled. Over the same period Australian production of CSG has increased almost five-fold. This is shown in Figure 3 below.

Figure 3: Australian Production of Natural Gas and Coal Seam Gas – 2010-11 to 2017-18 (Million Cubic Metres or Mm<sup>3</sup>)



The most significant conventional gas-producing basins are the Carnarvon and Bonaparte Basins off Western Australia and the Gippsland Basin off Victoria (Geosciences Australia, 2018). Production of CSG is mainly from the Bowen and Surat Basins in Queensland with a very small amount produced from the Sydney Basin as well as a miniscule amount from the Gunnedah Basin in NSW.

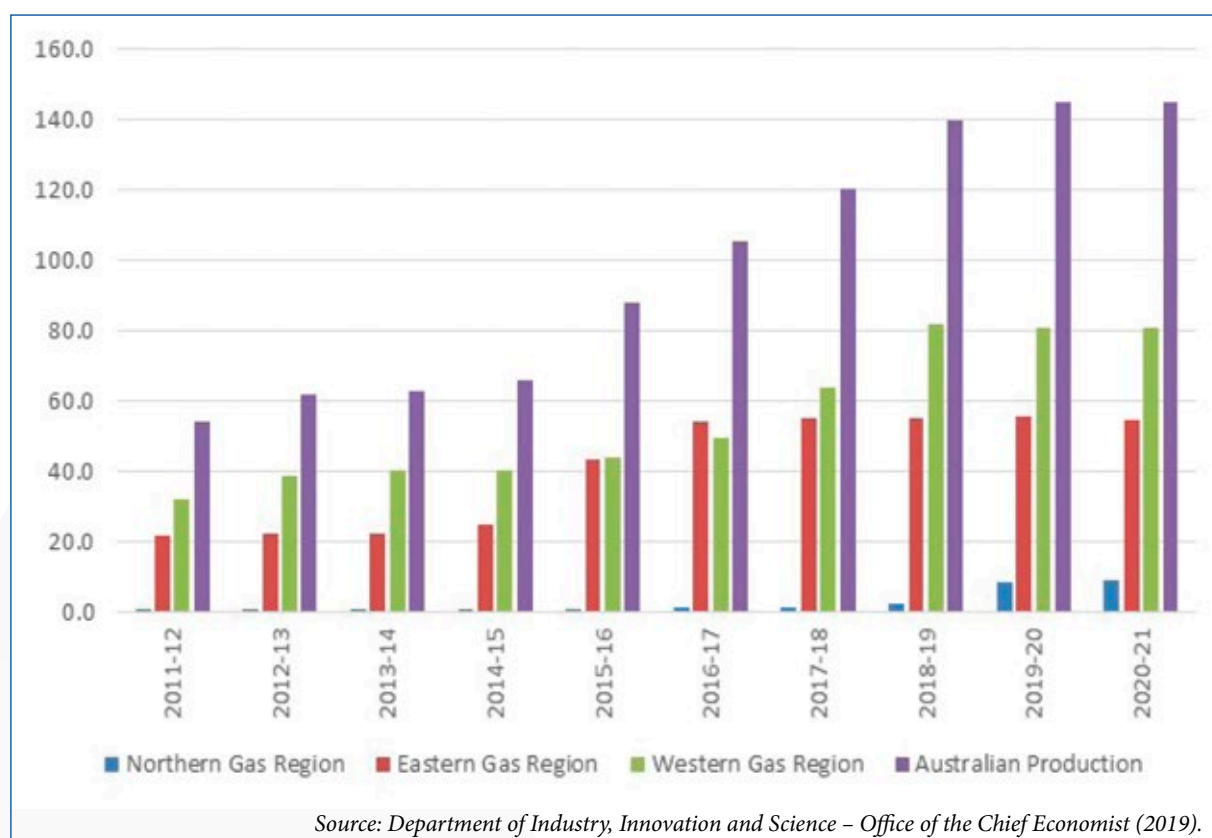
Australia's domestic gas market consists of three distinct regions, separated on the basis of the gas basins and pipelines that supply them (Australian Energy Market Commission, 2019):



- ▲ 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).<sup>3</sup> The gas basins that supply this market contain around one third of Australia's gas reserves. This region has moved rapidly from an isolated and self-sufficient market to one linked to international gas markets with the development of CSG projects in Queensland (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 12).
- ▲ Western Gas Region where the gas market contains over one half of Australia's gas reserves and is heavily focussed on exports but also supplies domestic consumption in Western Australia (Australian Energy Market Operator, 2019).
- ▲ Northern Gas Region is Australia's smallest producer and its basins provide gas for export and also for domestic consumption in the Northern Territory (Australian Energy Market Operator, 2019).

Natural gas production broken down between the three regions is provided in Figure 4 below.

Figure 4: Actual, Estimates and Forecasts for Natural Gas Production for Northern, Eastern and Western Gas Regions and Australia – 2011-12 to 2020-21 (Billion Cubic Metres or Bm<sup>3</sup>)



### 4.3 Australian Natural Gas Exports

Australia's LNG industry has expanded rapidly since the commencement of LNG exports from the North West Shelf project in Western Australia in 1989 (Geosciences Australia, 2018). Darwin LNG cargoes started in 2006, and the Queensland Curtis Island LNG cargoes commenced in January 2015 (Bethune & Wilkinson, 2019, p. 520; Australian Competition and Consumer Commission, 2016, p. 24). Australian exports of LNG have been ramping

<sup>3</sup> 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, 2019, p. 13).

up rapidly as new LNG plants are progressively commissioned to support the rapidly growing global demand for LNG (Geosciences Australia, 2018).

The North West Shelf project originally comprised two trains in 1989 (Government of Western Australia Department of Jobs, Tourism, Science and Innovation, 2019, p. 1). A third, fourth and fifth train were developed in 1992, 2004 and 2008 respectively.

The Darwin LNG project in the Northern Territory commenced exporting LNG in 2006 and comprises one train (ConocoPhillips Australia, 2019).

The Pluto project in Western Australia began exporting in May 2012 with a single train (Government of Western Australia Department of Jobs, Tourism, Science and Innovation, 2019).

Located in the Eastern Gas Region at Curtis Island near Gladstone in Queensland are three LNG 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).

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

The Gorgon project in Western Australia began exports from its first train in March 2016 and production from its second and third trains commenced in October 2016 and March 2017 (Government of Western Australia Department of Jobs, Tourism, Science and Innovation, 2019). The Wheatstone project, also in Western Australia, commenced production from its first train in October 2017 and second train in June 2018.

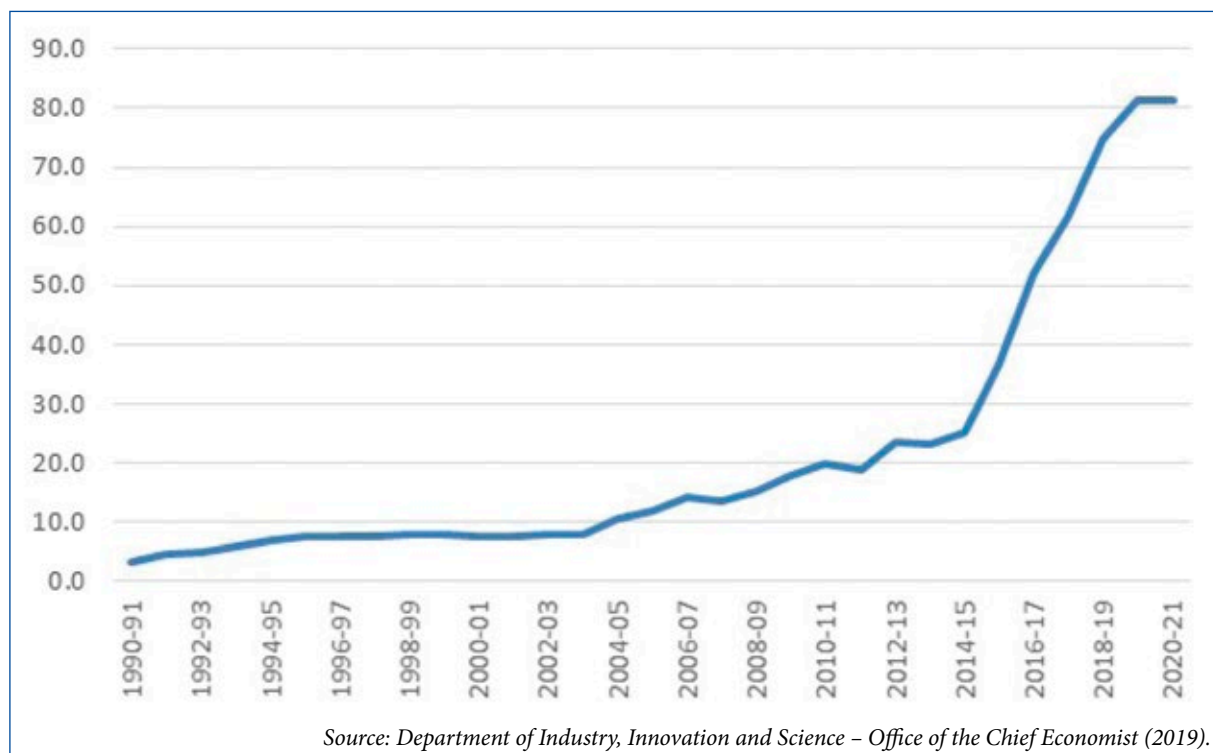
The Ichthys project exported its first LNG cargo in October 2018 and operates two LNG trains at Darwin in the Northern Territory (Government of Western Australia Department of Jobs, Tourism, Science and Innovation, 2019, p. 4).

The Prelude floating LNG facility, 475km north-north east of Broome, Western Australia, began production in late December 2018, with exports scheduled to begin in the first quarter of 2019 (Government of Western Australia Department of Jobs, Tourism, Science and Innovation, 2019, p. 4).

Australian exports of LNG have ramped up rapidly since 2014-15 as new LNG plants have come on stream. The expansion in Australian LNG exports is outlined in Figure 5 below along with export estimates and forecasts out to 2020-21.



Figure 5: Australian LNG Exports, Actual, Estimates and Forecasts – 1990-91 to 2020-21 (Million Tonnes)



Australia is forecast to edge past Qatar as the world's largest LNG exporter (on an annual basis) when exports reach an estimated 78 million tonnes in 2019, and extend its lead in 2020 as exports climb to an estimated 81 million tonnes (Department of Industry, Innovation and Science – Office of the Chief Economist, 2019, p. 60).

Most of Australia's LNG exports are shipped to Asian destinations (Bethune & Wilkinson, 2019, p. 520). Australia's share of LNG imports by the three largest importing countries is significant (37 per cent of China's, 34 per cent of Japan's and 22 per cent of Korea's) and this is supported by large investments from these countries (with other Asian and multinational companies) in Australian petroleum resources.

With more than a century of domestic reserves cover, an LNG export industry is a logical gas market development for Australia (Bethune & Wilkinson, 2019, p. 520). Despite this, there are regional disparities that could raise problems for supply availability and the future viability for some LNG export projects.

Western Australia's gas industry is based on very large resources and long distances from markets and is thus well suited to LNG development (Bethune & Wilkinson, 2019, p. 520). The Northern Territory is similar to Western Australia in this respect, although the Darwin LNG project needs additional gas to extend its operational life beyond the next few years as the Bayu-Undan gas field reaches its final stages.

However, a tightening supply situation in the Eastern Gas Region will put pressure on the future viability of the three LNG export projects operating at Curtis Island. According to the AEMO (2019, p. 40):

*From 2029, assuming no further developments beyond existing and committed projects, supply limitations across eastern and south-eastern gas production facilities are also forecast to drive shortfalls in Queensland LNG exports, with 8 PJ of CSG production needed to be diverted to ensure Queensland domestic demand is met in 2029, and 25 PJ in 2030.*

Dr Graeme Bethune and Rick Wilkinson (2019, p. 521) of energy advisory firm EnergyQuest have predicted:

*At least one, and possibly two, LNG trains on the east coast will shut down before the full term of their projects, either because of feed stock shortages or diversion of gas to the domestic market.*

The causes and implications of a tightening supply situation in the Eastern Gas Region are considered in the following sections.

## 5. EASTERN GAS REGION

### 5.1 Overview

Gas production in the Eastern Gas Region began around 50 years ago (Australian Energy Regulator, 2018a, 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. Gas powered 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.

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, 2018a, 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, South Australia, 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 6 below.

Figure 6: Eastern Gas Region



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 whereby 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). However, that changed with the establishment of the three LNG export projects at Curtis Island coupled with increasing domestic demand arising from GPG.

The development of the three LNG export projects transformed the Eastern Gas Region, giving producers a choice between exporting their gas or selling it domestically (Australian Energy Regulator, 2018a, p. 182). By 2018 more than 60 per cent of eastern Australian gas production was being exported. With domestic users now competing with overseas customers to buy Australian gas, prices in the domestic market have risen to align more closely with international gas prices.

Higher gas prices have also had an impact on electricity markets, which became more reliant on GPG following the closure of several coal fired generators in 2016 and 2017 (Australian Energy Regulator, 2018a, p. 182).

According to the Australian Competition and Consumer Commission (ACCC) (2017, p. 16):

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

## 5.2 Production

The main production basins within the Eastern Gas Region are the Surat and Bowen Basins in Queensland, the Cooper Basin in South Australia and Queensland and three basins off coastal Victoria, the largest of which is the Gippsland Basin. This is outlined in Table 3 below.

Table 3: Gas Basins Serving the Eastern Gas Region in 2017-18

Gas Basins	Gas Production 12 months to June 2018		2P Gas Reserves (August 2018)	
	Petajoules	Share of Eastern Australia Supply (%)	Petajoules	Share of Eastern Australia Supply (%)
Surat–Bowen (Qld)	1,368	73%	37,971	88%
Cooper (SA–Qld)	84	4%	1,034	2%
Gippsland (Vic)	291	15%	2,272	5%
Otway (Vic)	68	4%	502	1%
Bass (Vic)	18	1%	73	0%
Sydney and Narrabri (NSW)	6	0%	26	0%
Amadeus (NT)	10	1%	199	0%
Bonaparte (NT)	38	2%	830	2%
Eastern Gas Region Total	1,883		42,907	

Source: EnergyQuest, Energy Quarterly, September 2018 as cited by Australian Energy Regulator (2018a, p. 189).



Starting in the late 1990's, gas produced from vast coal seams in 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, aided by Queensland Government policy to mandate a level of GPG.

However, while a majority of Eastern Gas Region's gas reserves are located in the Surat and Bowen Basins, those reserves are now largely committed to the LNG export industry (Australian Energy Regulator, 2018a, p. 201).

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 BHP Billiton.

Gas production from the Gippsland Basin has increased in recent years in response to increasing demand for gas in the Eastern Gas Region (Australian Competition and Consumer Commission, 2017, p. 30). On average over the previous five years, gas from the Victorian basins has supplied 150 PJ per annum to Tasmania, NSW, and South Australia, from production surplus to Victorian gas consumption requirements (Australian Energy Market Operator, 2019, p. 35).

While gas production in the Gippsland Basin reached new heights during 2017, with producers supplying 435 PJ to the Eastern Gas Region, this trend will not continue (Australian Energy Market Operator, 2018a, p. 5). The three largest gas fields in the Gippsland Basin – Marlin, Barracouta, and Snapper – are all in natural decline and nearing the end of production (Owen, 2017). According to the ACCC (2017, p. 30):

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

In turn, the production surplus available to be exported to Tasmania, NSW, and South Australia from Victoria is expected to decline to 23 PJ by 2023 (Australian Energy Market Operator, 2019a, p. 3). In relation to Victorian gas supply, the AEMO (2019a, p. 6) has commented:

*Future gas supply is expected to be from a combination of smaller, higher cost fields and the importation of LNG into Victoria ...*

Historically, 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, 2018a, p. 188).

The bulk of production from the Cooper Basin has now been committed to the LNG projects in Queensland (Australian Competition and Consumer Commission, 2017, p. 29). Santos entered an agreement in 2010 to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional gas reserves (Australian Energy Regulator, 2018a, p. 188).

NSW has only been a small producer of gas largely from coal seams 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 comes 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, 2017a). The Project produces natural gas from coal seams 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.

The Camden Gas Project originally had 144 wells, 86 of which are currently in production (AGL Energy Limited, 2019). The other major element of the Camden Gas Project is the Rosalind Park Gas Plant in Menangle, where natural gas is collected via low pressure underground gathering lines, compressed, dried and made ready for use by households and businesses, and transmitted into the greater Sydney natural gas network (AGL Energy Limited, 2017a). 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.

As discussed above, a small amount of gas produced by Narrabri Gas Project exploration wells is being used to power the Wilga Park Power Station.

Aside from the new Sole Gas Project by Cooper Energy expected to produce around 24 PJ per annum in the Gippsland Basin, there are very limited prospects of new gas supply emerging from production basins in the southern states in the immediate future (Australian Competition and Consumer Commission, 2017, p. 34).

### 5.3 Domestic Demand

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 for domestic users (Bethune & Wilkinson, 2019, p. 520). According to the AEMO (2019, p. 17), export LNG demand will continue to dominate forecast trends, representing approximately 70 per cent of total annual gas consumption across a 20-year outlook.

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 now dominated by the LNG export sector.

Table 4 below provides the estimated gas consumption by region and purpose within the Eastern Gas Region during 2018.



Table 4: Estimated Regional Consumption of Gas within the Eastern Gas Region by Sector – 2018\*

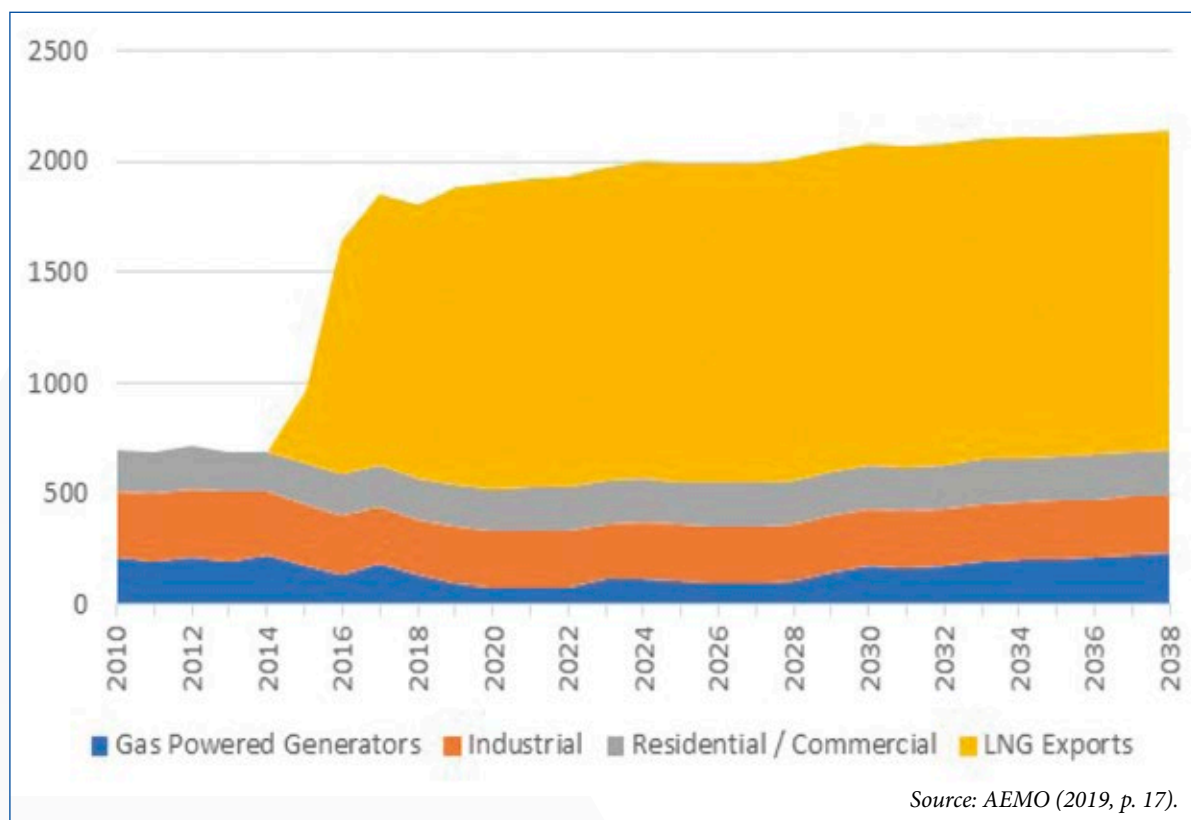
Region	Residential / Commercial (%)	Industrial (%)	Gas-Powered Electricity Generation (%)	LNG Exports (%)	Regional Gas Consumption
Queensland	< 1%	7%	2%	90%	1,380 PJ
New South Wales	42%	48%	10%	0%	116 PJ
South Australia	12%	27%	62%	0%	93 PJ
Tasmania	8%	51%	41%	0%	10 PJ
Victoria	58%	31%	11%	0%	212 PJ
<b>Total</b>	<b>10%</b>	<b>14%</b>	<b>7%</b>	<b>68%</b>	<b>1,811 PJ</b>

*Source: AEMO (2019, p. 20).*

\* Does not include metered gas that enters the gas network but that does not reach consumers.

Actual and future forecast consumption of natural gas by the AEMO is outlined below in Figure 7, which outlines the significant ratcheting up of gas consumption by the LNG export projects since 2014.

Figure 7: Eastern Gas Region Natural Gas Consumption Actual and Forecast by Sector, 2019-38



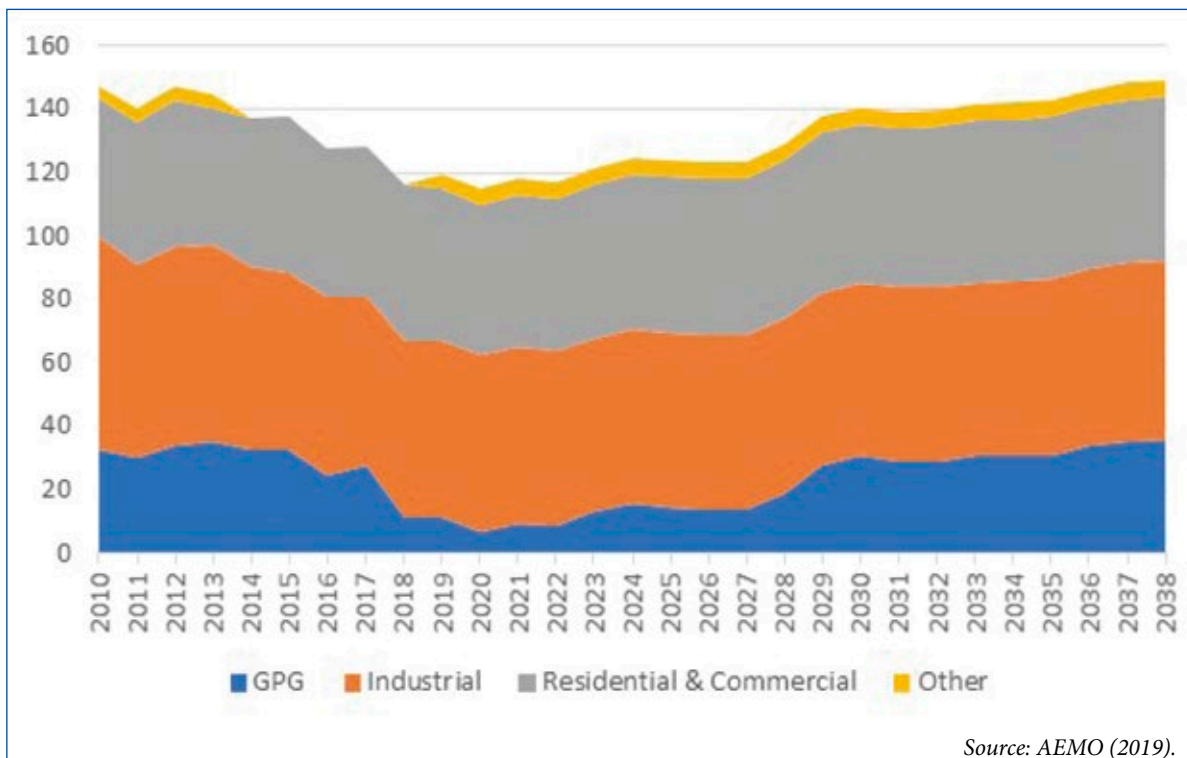
### 5.3.1 Natural Gas Demand in New South Wales

The demand for natural gas in NSW has declined over recent years.

From 2014 to 2018, annual consumption of natural gas in NSW fell by 15 per cent from 137 PJ to around 116.1 PJ in 2018. Over this time, the major contributor to the fall in consumption has been reduced demand from GPG

whose consumption has fallen from 32.7 PJ in 2014 to 11.1 PJ in 2018. This is shown in Figure 8 below along with the latest available forecasts from the AEMO (2019).

Figure 8: New South Wales Natural Gas Consumption Actual and Forecast by Sector (PJ), 2010-38



Note: Forecast is the Neutral scenario outlined by the AEMO (2019).

The fall in NSW demand for GPG has been largely due to increased penetration of renewable energy generation (Australian Energy Market Operator, 2019, p. 4). In the 2018 calendar year, nearly 2,000 megawatts (MW) of new utility-scale renewable energy capacity was installed in the National Electricity Market (NEM), while distributed energy resources such as rooftop photovoltaics (PV) continued to grow.

## 5.4 Demand and Supply Balance

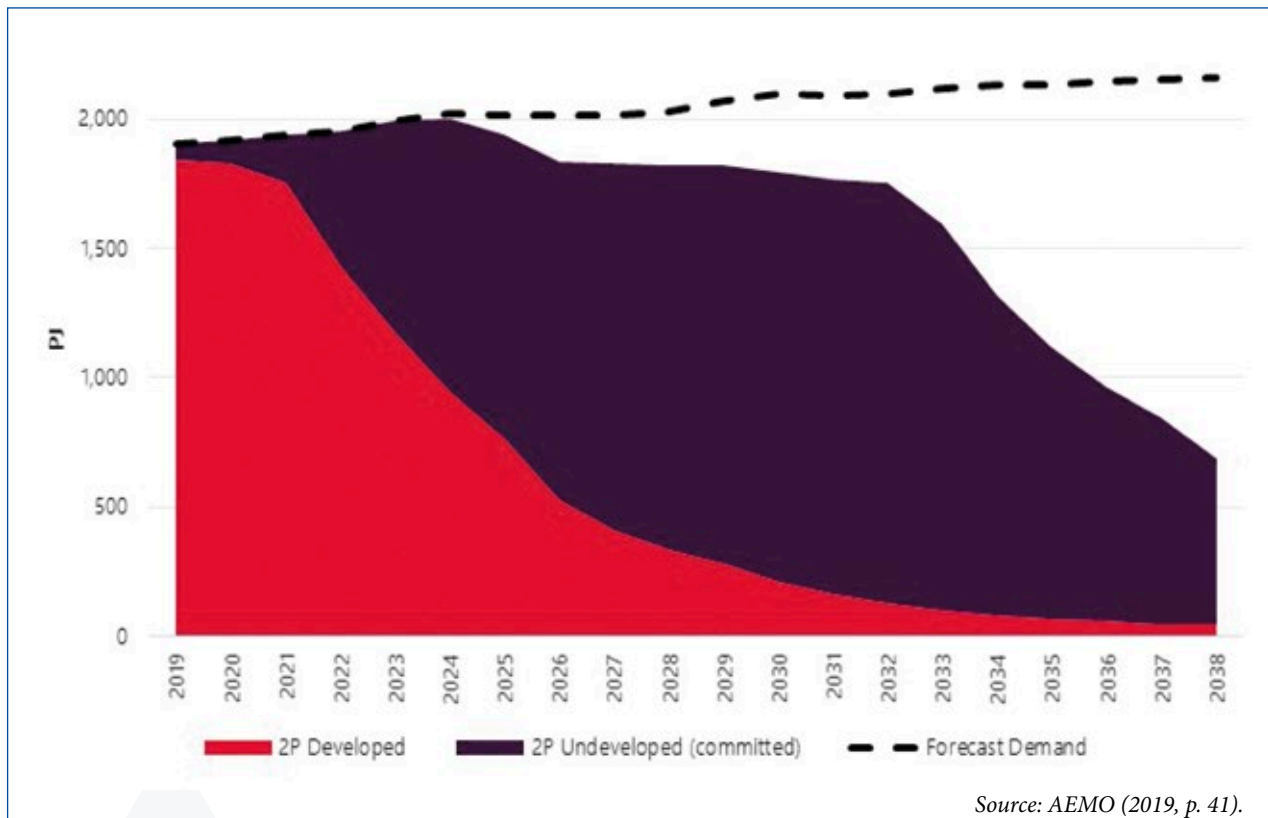
Numerous parties have predicted future gas supply shortfalls in the Eastern Gas Region in the foreseeable future. According to the AEMO (2019, p. 40) earlier this year:

*From 2024, the forecast southern supply (including committed gas projects) is projected to be insufficient to meet forecast demand if no further sources of gas or alternative infrastructure are developed. Furthermore, infrastructure constraints will mean additional gas cannot be transported from Queensland or the Northern Territory to southern states. Supply shortfalls are observed in southern states, driven by forecast decline from southern fields and infrastructure limitations.*

*From 2029, assuming no further developments beyond existing and committed projects, supply limitations across eastern and south-eastern gas production facilities are also forecast to drive shortfalls in Queensland LNG exports, with 8 PJ of CSG production needed to be diverted to ensure Queensland domestic demand is met in 2029, and 25 PJ in 2030.*

The forecast future supply shortfall by the AEMO is outlined in Figure 9 below.

Figure 9: Projected Eastern Gas Region Production (Export LNG and Domestic User), 2019-38; Supply from Existing Projects and Committed Developments (PJ)



Similarly, Dr Graeme Bethune and Rick Wilkinson (2019, p. 521) of energy advisory firm EnergyQuest have predicted a looming gas shortfall albeit a little later:

*... current east coast 2P reserves will not meet demand by 2026 and several options will need to be considered:*

- *Increase exploration and bring on unknown, low cost and large volume gas resources;*
- *Import LNG;*
- *Decrease demand;*
  - *Shut down one or two LNG trains; and/or*
  - *Destroy gas demand with higher gas prices.*

Potential gas shortages and soaring gas prices has prompted the Commonwealth Government to intervene in the market to secure domestic supply and ease supply pressures on consumers (Billimoria, Adisa, & Gordon, 2018, p. 1370). In July 2017 the Commonwealth Government launched the Australian Domestic Gas Security Mechanism (ADGSM) to ensure there is a sufficient supply of natural gas to meet the forecast needs of energy users within Australia (Department of Industry, Innovation and Science, 2019). Under the ADGSM, if LNG export projects' use of domestic natural gas results in a supply shortfall in a domestic market, those projects may be required to limit their exports or find new gas sources.

To avoid triggering the ADGSM, the LNG export projects in October 2017 entered into a Heads of Agreement with the Commonwealth Government whereby they committed to divert enough gas to the domestic market to avoid a shortfall, and to offer any uncontracted gas to the domestic gas market on competitive terms, before offering it to international buyers during the 2018 and 2019 calendar years (Department of Industry, Innovation and Science,

2019). The LNG export projects entered into a new Heads of Agreement with the Commonwealth Government in September 2018 providing similar commitments for the 2019 and 2020 calendar years.

The Commonwealth Government announced on 6 August 2019 that it will bring forward a review of the ADGSM to commence in September 2019 and that it will also consider options to establish a prospective national gas reservation scheme. (Canavan, Frydenberg, & Taylor, 2019).

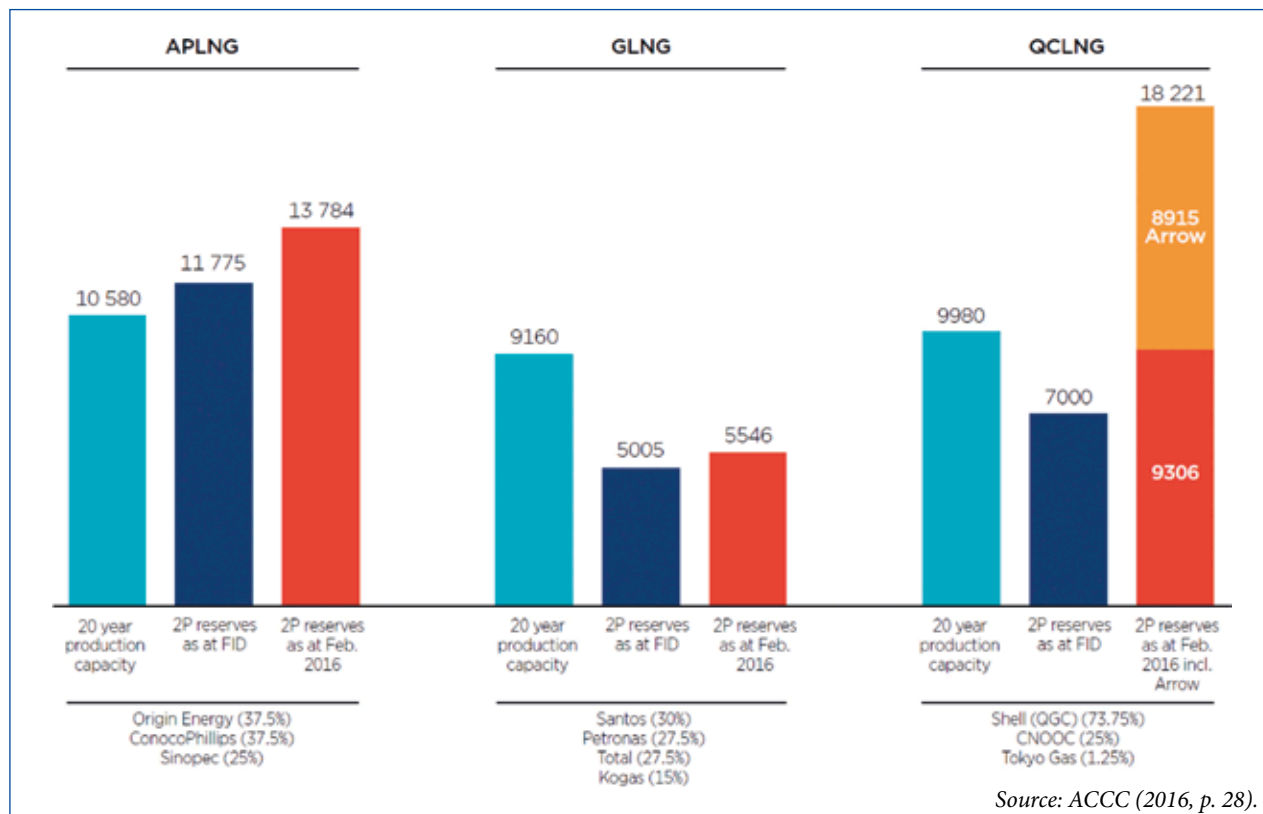
The supply of natural gas in the Eastern Gas Region has tightened since the Queensland LNG export projects started to draw on reserves from the Eastern Gas Region (Australian Energy Regulator, 2017, p. 8). In this regard, the AEMO (2013, p. iv) warned as long ago as 2013:

*Potential gas supply shortfalls<sup>5</sup> may occur in Queensland if facilities that are currently dedicated to domestic demand are prioritised to supply rising LNG export demand. Without further production investment, potential shortfalls in Queensland may exceed 250 [terajoules per day] once all six LNG trains reach full output. This is projected to occur in 2019.*

*If production in Queensland and South Australia is prioritised for export, there will be flow-on effects to New South Wales with potential shortfalls of 50–100 [terajoules per day] over winter peak demand days from 2018.<sup>4</sup>*

Decisions made by one of the Queensland LNG export projects stand out as the root cause of future impending natural gas shortfalls in the Eastern Gas Region. While APLNG and QCLNG primarily expected to meet their LNG export commitments through the development of gas resources owned by them, the Santos-led GLNG always expected to source gas from other producers in the Eastern Gas Region to supplement its CSG reserves (Australian Competition and Consumer Commission, 2016, p. 28). This is reflected in Figure 10 below which shows the total production capacity of the two GLNG trains significantly exceeded the volume of gas that GLNG could produce from its 2P CSG reserves at the time the project was sanctioned.

Figure 10: Expected LNG Plant Production Capacity and 2P Reserves of the Queensland LNG Projects

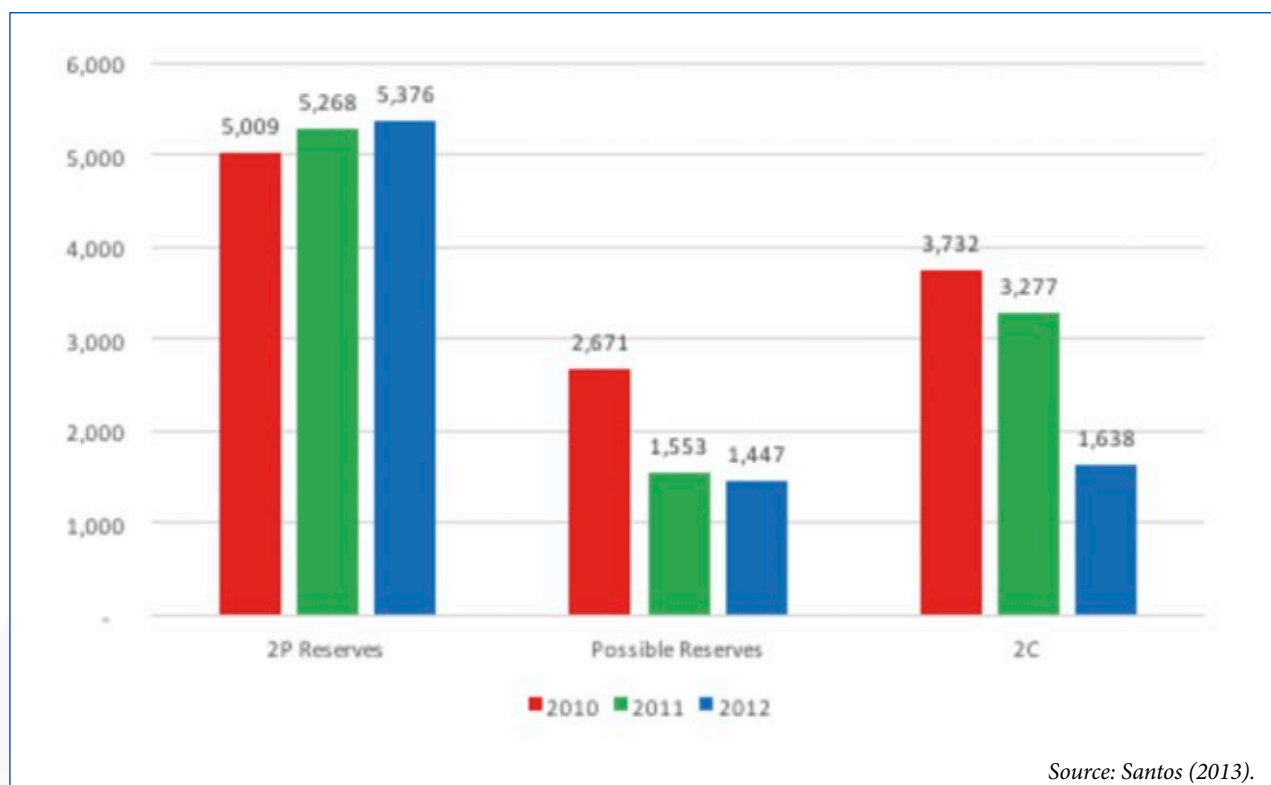


4 One petajoules is equal to 1000 terajoules (TJ).

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

However, the contention by Netherland, Sewell & Associates that possible reserves and contingent resources would eventually be converted over to 2P reserves became increasingly difficult to justify in the face of GLNG reserve updates provided by Santos (2013). While GLNG actual 2P reserves did increase, possible reserves and contingent resources slumped with each further gas reserve update. This is shown in Figure 11 below.

Figure 11: Proven and Probable Reserves (2P), Possible Reserves and Contingent Resources (2C) for GLNG (PJ) – 2010 to 2012 (year end to December)



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

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

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

<sup>5</sup> Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves (Society of Petroleum Engineers, 2017, p. 13).

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

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

*The key issue you've got to be absolutely confident of when you sanction trains is that you've got the full gas supply to meet your contractual obligations that you've signed up with a buyer.*

*Now you should have confidence that we will sanction the second train because we will have signed up with the buyers to supply gas from that second train. In order to do it, we need to have absolute confidence ourselves that we've got all the molecules in order to fill that second train. (CQ Transcriptions, LLC., 2010)*

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

In 2016, the ACCC (2016, p. 24) observed the Santos-led GLNG had been purchasing substantial volumes of gas in the domestic market over the previous five years to supplement production from its inadequate reserves. In December 2016 Santos (2016b) reported on the third party gas supply contracts that GLNG had entered, a summary of which is presented below in Table 5.



Table 5: GLNG Third Party Gas Supply Agreements

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

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

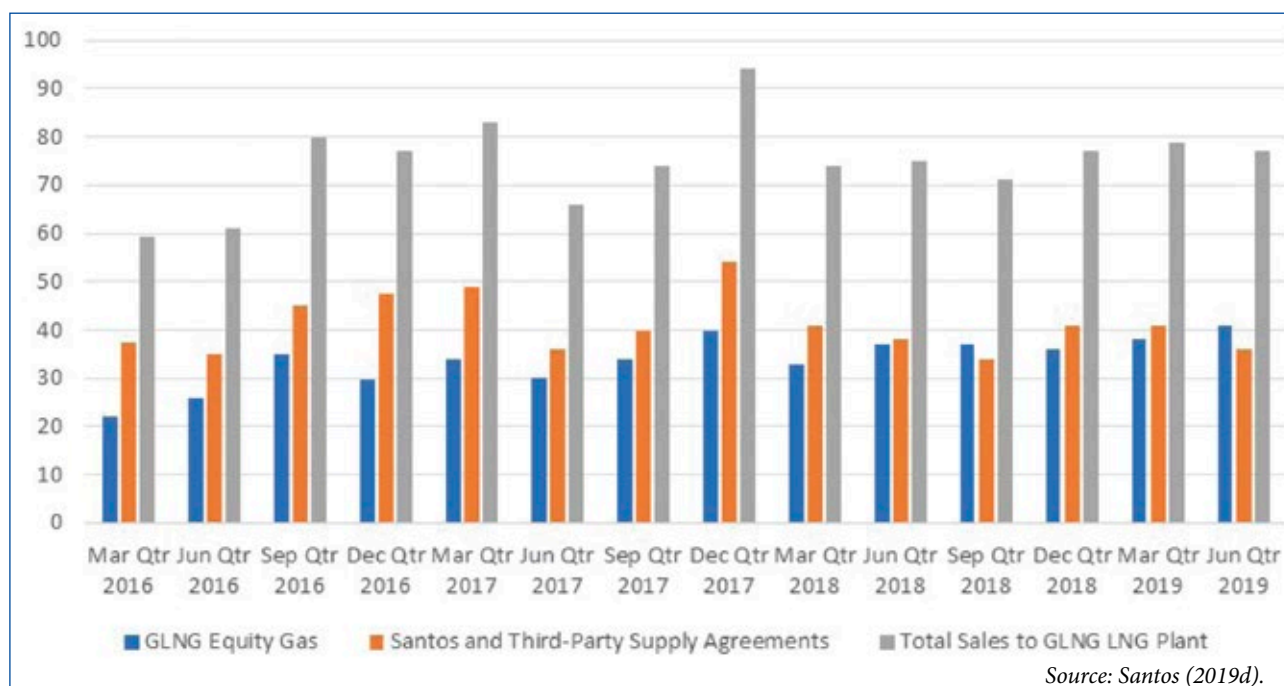
The available evidence suggests Santos did not in fact possess all the *molecules* it required to fill the second train for the GLNG project as suggested by its former Managing Director and Chief Executive Officer. Furthermore, the number of third party gas supply agreements entered into by GLNG commencing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

*The project may initially supply domestic gas markets, but it is not diverting gas from local markets to export markets. The project's supply of gas to the domestic market is uncertain at this stage. Options to manage ramp up gas and any gas that is surplus to the requirements of the LNG facility include a range of commercial and technical possibilities. Therefore the project has no direct implications for domestic gas prices. The gas to supply the LNG facility will come from newly developed CSG fields. The amount of gas is very small relative to the identified conventional and CSG fields reserves available to supply the Australia east gas fields. It is therefore unlikely to contribute to a future shortage of gas in the domestic market.*<sup>6</sup>

As a matter of fact, the Santos-led GLNG project has diverted natural gas from domestic users to export markets as it has not exclusively relied upon newly developed CSG fields for its gas supply, and it has been the major contributor towards any impending natural gas shortfalls within the Eastern Gas Region. The September quarter 2018 and the June quarter 2019 have been the only occasions when GLNG has sourced more than 50 per cent of the gas supplied to its LNG plant from its own sources, with the bulk of gas generally supplied by Santos and through other third-party agreements. This is outlined in Figure 12 below.

<sup>6</sup> Emphasis not in the original document.

Figure 12: Sales of Gas to GLNG LNG Plant – March Quarter 2016 to June Quarter 2019 (PJ)



In October 2017 NSW Deputy Premier John Barilaro (2017) commented following Santos reporting that GLNG had sourced 59 per cent of the gas its processed in the March quarter 2017 from third-party agreements:<sup>7</sup>

*Another gas company confirmed that in the March quarter this year, 59 per cent of its exported gas was bought from third party domestic suppliers.*

*In short, they're sucking gas out of the domestic market to fulfil export contract shortfalls.*

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

*The facts of the role that Santos and its partners in the GLNG project have played in delivering the nation to gas shortage are well appreciated and incontrovertible.*

*Despite some internal debate, Team Santos decided to proceed with the construction of a second train at its Curtis Island liquefied natural gas plant.*

*That debate was triggered by the fact that Santos did not have enough gas to justify that investment. But, because it found customers enough prepared to sign up to long-term contracts, the GLNG partnership took the risk that the oil price would hold at better than \$US70 a barrel and thus oil-linked LNG prices would ensure the venture would make money by filling its freezer with other people's gas.*

*Then the oil price went bust and with it went that investment paradigm.*

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

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

...

<sup>7</sup> See Santos (2017).

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

Apparently not willing to let a good crisis go to waste, Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its Narrabri Gas Project, without acknowledging the central role it played in creating the circumstances that it now claims the Narrabri Gas Project will address. The Preliminary Environmental Assessment for the Narrabri Gas Project in 2014 stated:

*The anticipation of restricted gas supply to NSW heightens the need for a local gas resource for NSW to provide increased security for the current demand and to meet the projected future demand. The proposed development would provide infrastructure to help facilitate overcoming these predicted challenges and thereby meet projected demand for eastern states over the next decades. (GHD, 2014, pp. 19-20)*

*The do nothing option would result in the absence of potentially 50% of NSW gas requirements being available for supply to the NSW gas market. (GHD, 2014, p. 20)*

Similarly, in early 2015 Santos (2015a, pp. 12-13) commented on the prospect of looming gas supply shortages in NSW in its submission to the NSW Legislative Council Select Committee on the Supply and Cost of Gas and Liquid Fuels in following terms:

*It is now widely accepted that NSW may have gas shortages and challenges after 2016 when the existing supply contracts with NSW gas retailers from the Cooper Basin come to an end ... there will be a significant shortfall in gas for NSW customers as contracts roll-off and instead the gas from the Cooper Basin and Queensland is contracted to supply export customers via the Gladstone LNG projects or domestic customers in Queensland and SA.*

*...*

*As a result after 2016, NSW will be predominately supplied, as much as is possible, from Victoria. The supply will be impeded by transmission constraints, with gas flowing up the Eastern Gas Pipeline (EGP) as well as the NSW-Victoria interconnector ... This is despite adequate Moomba-Sydney Pipeline (MSP) capacity being available for supply from the Cooper Basin and/or Queensland into NSW as that gas is very unlikely to be available.*

*From 2016 NSW will increasingly need to compete for gas supplies with others in the Eastern Gas Market. If NSW gas resources are not developed it is unclear where the additional gas required to meet static demand will come from, notwithstanding any growth in demand.*

In 2017 the Environment Impact Statement for the Narrabri Gas Project also focused on impending gas shortages in NSW in support of the project:

*From 2017 a major shift will occur when all three liquefied natural gas (LNG) facilities in Queensland will reach more stable production levels. The majority of the gas that was previously contracted from the Cooper Basin will no longer be available to supply NSW, as it has been contracted from 2016 to meet some of the supply requirement of these Queensland natural gas facilities.*

*The absence of alternative sources of gas going forward, coupled with the diversion of gas from the Cooper Basin to fulfil LNG export contracts, means NSW will require the vast majority of its gas to be supplied from Victoria. This reliance on a single supply source may pose significant security of supply risk in the event of an interruption, as occurred in 1998 when there was an event at the Longford gas plant in Victoria that resulted in severe gas shortages across the state. (GHD, 2017, pp. ES.5-ES.6)*

Under the ADGSM, orders can only be issued against LNG exporters that are drawing more gas from the domestic market than they are putting into it (Stevens, 2017). Matthew Stevens (2017) has suggested the ADGSM might be better described as the *Santos stick*, inferring that Santos was specifically targeted in the policy design:

*The wisdom accepted is that this is a cleverly designed lever aimed pretty much exclusively at encouraging Santos and its partners to accept that they have failed the test of their social licence by drawing excessively on the domestic market for the gas required to feed their two export gas trains.*

The Santos Managing Director and Chief Executive Officer Kevin Gallagher responded in the media to the Commonwealth Government's announcement of the ADGSM by suggesting that it was "purely something that's designed to take gas off of Santos" (England, 2017). However, following the implementation of the ADGSM, Santos changed both its rhetoric and conduct, announcing a series of new gas supply arrangements whereby it would be selling natural gas back into the Eastern Gas Region for domestic use, with Mr Gallagher declaring in September 2017:

*Over the last few months, Santos has been working constructively with the Federal Government and our GLNG partners to supply additional gas to the east coast domestic market. (Santos Ltd, 2017a)*

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

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

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

As noted earlier, Dr Graeme Bethune and Rick Wilkinson (2019, p. 521) of energy advisory firm EnergyQuest have predicted that at least one, and possibly two LNG trains on the east coast will shut down before the full term of their projects, either because of feed stock shortages or diversion of gas to the domestic market. Dr Bethune has observed the Santos-led GLNG project was the project furthest away from reaching capacity, that 44 per cent of Santos GLNG CSG reserves were not of "good quality" and that "unless Santos has great exploration success, the second train at GLNG might ultimately be under threat" (Wray & Annett, 2019).

#### 5.4.1 Future Supply Options

As the expected impending shortfall of gas in the Eastern Gas Region approaches, increased gas supply and exports from Queensland can make up some of the shortfall in the southern states (Bethune & Wilkinson, 2019, p. 521). However, there are infrastructure limitations on how much gas can be exported from Queensland to the southern states. The existing pipeline infrastructure cannot move more than 140 PJ per annum without more investment. Additional investment in pipeline infrastructure will face a number of challenges (Bethune & Wilkinson, 2019, p. 521). First, there are no low cost 2P gas reserves left available to supply a pipeline long-term for the southern states.

Second, while CSG from the Surat and Bowen Basins can meet some of the southern shortfall up until 2026, the period before the decline of the CSG fields is only a few years away and not sufficient to underwrite further pipeline investments unless gas already committed to the LNG export projects is redirected toward domestic users (Bethune & Wilkinson, 2019, p. 521). Essentially, CSG reserves developed for export in Queensland are not sufficient to supply both the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).

While there has been a response from gas producers in the form of new gas developments, the currently approved projects and near term proposals are mostly small in scale and may not be able to fill the gap being created by

declining reserves in large historic gas fields (Collins, Cockerill, & Rasheed, 2019, p. 542).

According to the AEMO (2019a, p. 58), if there is insufficient new gas production in the southern states then they will become more reliant on imports from either Queensland or will require the construction of an LNG import terminal.

## 6. NARRABRI GAS PROJECT IN THE CONTEXT OF NSW GAS SUPPLY

### 6.1 NSW Government Policy

In NSW CSG is owned by the Crown (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 8). Section 6(1) of the *Petroleum (Onshore) Act 1991* (NSW) states that:

*All petroleum, helium and carbon dioxide existing in a natural state on or below the surface of any land in the State is the property of the Crown, and is taken to have been so always.*

Gas companies can extract CSG from beneath the ground in return for contributing royalties to the NSW Government (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 8). However, to do this, the *Petroleum (Onshore) Act 1991* (NSW) requires them to:

- ▲ hold a petroleum title
- ▲ gain access to the surface of the ground by entering into a written access arrangement with the landholder(s).

Gas companies are required to hold different petroleum titles (or licences) at different stages of the CSG exploration and production process (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 9).

A Petroleum Special Prospecting Authority gives the holder the exclusive right to explore for petroleum using low-impact methods over the designated area (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 92). In the initial stages of a project, the company must hold a Petroleum Exploration Licence (PEL) which gives the holder the exclusive right to explore for petroleum within the exploration licence area during the term of licence (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 9).

A Petroleum Assessment Lease (PAL) allows the holder to maintain a title over a potential project area without having to commit to further exploration (i.e., between exploration and production phases) (Independent Pricing and Regulatory Tribunal of New South Wales, 2015, p. 92). A Petroleum Production Lease (PPL) gives the holder the exclusive right to extract petroleum within the production lease area during the term of the lease

On 21 May 2011 the NSW Government announced the staged implementation of its *Strategic Regional Land Use Policy* that sought to “strike the right balance between our important agricultural, mining and energy sectors – while ensuring the protection of high value conservation lands” (Hazzard, 2011). Under the policy, an immediate 60-day moratorium on the granting of new coal, CSG, and petroleum exploration licences in NSW was imposed.

On 21 July 2011 the NSW Government announced a moratorium on fracking until 31 December 2011 (Hartcher, 2011a). On 2 December 2011 the NSW Government announced the extension of its moratorium on fracking until April 2012 that only applied to new fracking approvals, pending the completion of an independent review process (Hartcher, 2011).



On 6 March 2012 the NSW Government released a draft Code of Practice for CSG explorers and new Community Consultation Guidelines as part of a suite of controls regulating the CSG industry under the NSW Government's Strategic Lands package (Hartcher, 2012).

On 19 February 2013 the NSW Government announced further regulation of the CSG industry in NSW, including the introduction of a two kilometre exclusion zone imposed around residential zones to prevent new CSG exploration, assessment and production activities (both surface and underground) and the introduction of exclusion zones to apply in relation to identified Critical Industry Clusters – viticulture and the equine industry (O'Farrell, 2013).

On 12 November 2013 the NSW Government implemented a hold on exploration and extraction of natural gas from coal seams in the 'Special Areas' zone within Sydney's drinking water catchment (Hartcher, 2013). On 26 March 2014 the NSW Government announced a freeze on the processing of new PEL applications and an audit of existing PELs (Roberts, 2014).

On 13 November 2014 the NSW Government (2014) released the NSW Gas Plan. Under the plan, the NSW Government (2014, p. 6) moved to extinguish all existing PEL applications and established a one off buy-back of PELs. It also sought to implement and enforce a 'use it or lose it' policy requiring titleholders to commit to developing the state's resources or risk losing their titles.

According to Edward Boyd (2019), NSW Political Reporter for *The Daily Telegraph*:

*The restrictions effectively make the Santos Narrabri Gas Project in northern NSW the only remaining viable option for gas production in our state.*

## 6.2 Narrabri Gas Project Production

The Narrabri Gas Project involves the progressive installation of up to 850 new gas wells on up to 425 new well pads over approximately 20 years and the construction of gas processing and water treatment facilities (GHD, 2017, p. ES.1).

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

It is claimed the Narrabri Gas Project has the capacity to deliver up to 200 terajoules (TJ) of gas per day (GHD, 2017, p. 1.11). This converts to an annualised figure of 73 PJ. It was claimed in the Preliminary Environmental Assessment that the project would have the capacity to produce approximately 70 PJ of gas per annum (GHD, 2014, p. 19). However, an estimate by the Commonwealth Government has put the expected production of the Narrabri Gas Project at 36 PJ of gas per annum (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018).

Based on a production capacity of up to 200 TJ of gas per day, it has been claimed that the Narrabri Gas Project could supply up to 50 per cent of current gas demand for NSW based on gas consumption of 138 PJ in 2013 (GHD, 2014, p. 19). However, based on current reduced estimated NSW gas consumption of 116.1 PJ in 2018 and reduced gas production of 36 PJ per annum from the project, this comes to around 31 per cent of current NSW gas demand.

### 6.3 NSW Gas Supplies and the Narrabri Gas Project

NSW is currently heavily dependent on imports from other states for its gas supplies.

As previously discussed, the only indigenous gas production in NSW is the Camden Gas Project operated by AGL that currently supplies around 5 per cent of NSW demand. However, the Camden Gas Project is due to cease production in 2023.

In addition, the gas fields that have traditionally supplied the NSW market, primarily the Gippsland Basin in Victoria and the Cooper Basin in South Australia and Queensland, are in natural decline. Furthermore, most of the remaining future gas reserves in the Cooper Basin have been contracted to GLNG. In addition, CSG reserves developed by LNG export projects in Queensland are not sufficient to supply both the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).

Under these circumstances, the development of the Narrabri Gas Project would provide additional gas supply for NSW. In this respect, Santos (2015a) is arguably broadly correct in its contention:

*The Narrabri Gas Project could be a significant contributor to NSW's emerging predicament, should the project proceed. The project can supply up to 50 per cent of NSW's daily gas requirements via a dedicated pipeline heading south.*

However, the Narrabri Gas Project will not provide a complete solution to any impending gas shortfalls in NSW. NSW will still need to find additional sources of supply, either from new projects from domestic sources within the Eastern Gas Region or from LNG imports to supplement any supplies it may receive from the Narrabri Gas Project in the event it proceeds.

### 6.4 Relative Production Costs

As part of its annual *Gas Statement of Opportunities* report for eastern and south-eastern Australia, the AEMO (2019) publishes estimates of natural gas resources and estimates of production costs for both developed and undeveloped gas projects.<sup>8</sup> This reveals the Narrabri Gas Project is a relatively high cost gas development project with an estimated production cost of \$7.40 per gigajoule (GJ), ranking 41 out of 51 actual and undeveloped gas projects.<sup>9</sup>

There are 18 developed and 22 undeveloped gas projects with lower estimated production costs than the Narrabri Gas Project. The 22 undeveloped gas projects with lower production costs represent in excess of 65,000 PJ of 2P and 2C natural gas resources. The estimate of production costs and gas resources for both developed and undeveloped gas projects is provided in Figure 13 below, whereby the estimated production costs for each project provides an effective gas supply curve for the Eastern Gas Region.

The Narrabri Gas Project will be more expensive to develop than 65,000 PJ worth of other undeveloped gas projects. This is the equivalent to 36 years of current gas consumption for the Eastern Gas Region including both domestic users and LNG export demand.<sup>10</sup>

The costs of transporting gas by pipeline must also be added to all sources of gas supply. It has previously been estimated that transmission adds \$2 per GJ to the cost of delivering gas from the Narrabri Gas Project (Forcey & McConnell, 2017, p. 39).

Pipeline infrastructure operator APA (2018, p. 2) is currently progressing preliminary studies for construction of a 460 kilometre gas pipeline – the Western Slopes Pipeline, connecting natural gas from the Narrabri Gas Project to

<sup>8</sup> The data is sourced from the Core Energy Group and gas industry participants.

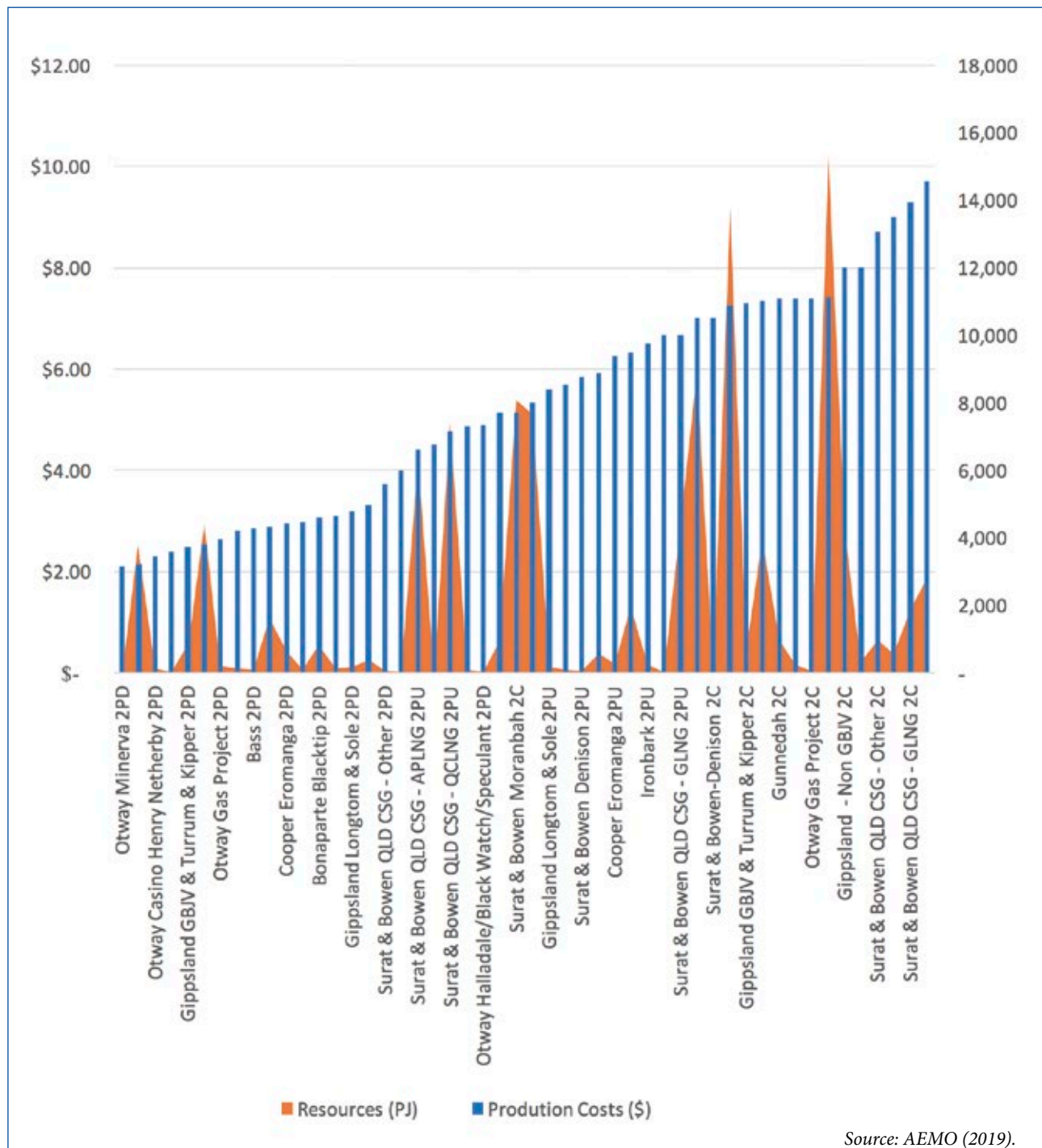
<sup>9</sup> One petajoule is equal to one million gigajoules.

<sup>10</sup> Based on analysis previously undertaken by Forcey & McConnell (2017, p. 39).

the NSW gas transmission network, via the Moomba to Sydney Pipeline. The Core Energy Group (2015, p. 10) has previously suggested an indicative tariff in the order of \$0.10 per 100 kilometres of gas transmission pipeline. The current tariff for the Moomba to Sydney Pipeline is \$1.1 per GJ (APA Group, 2019). Based on this publicly available information, a transmission charge to deliver gas from the Narrabri Gas Project to Sydney is probably in the order of \$1.60 per GJ.

All this suggests the cost of delivered gas from the Narrabri Gas Project is likely to be somewhere in the order of \$9.00 to \$9.40 per GJ to Sydney.

Figure 13: Estimated Supply Curve for Developed and Undeveloped Gas Project (\$/GJ) and Estimated 2P and 2C Gas Resources for the Eastern Gas Region (PJ)\*



\* 2PD – 2P developed gas project, 2PU – 2P undeveloped gas project, 2CU – 2C undeveloped gas project.

## 6.4 Destination of Gas from the Narrabri Gas Project

In its takeover of Eastern Star Gas, Santos (2011b, p. 8) emphasised its access to the LNG export market through the Wallumbilla Gas Supply Hub in Queensland:

*Santos access to Wallumbilla infrastructure enables entry to LNG export projects at Gladstone.*

In effect, Santos was implying that a potential destination for gas produced from the Narrabri Gas Project could in fact be LNG export markets. Since that time, Santos has modified its position as to the likely destination of gas produced from the Narrabri Gas Project.

In its submission to the inquiry into the supply and cost of gas and liquid fuels in NSW, Santos (2015a, p. 8) declared:

*The Narrabri Gas Project has the potential to supply up to 200 terajoules of natural gas per day, or up to half of NSW's natural gas needs and it has been repeatedly stated that the gas will be made available for the NSW market. The gas will be extracted from coal seams in and around the Pilliga, near Narrabri and will be transported to NSW customers via a dedicated pipeline heading south from the Project area to connect to the existing Moomba to Sydney Pipeline.*

In the 2017 Environmental Impact Statement (EIS) for the Narrabri Gas Project, it stated:

*The gas would be made available to the NSW market via a high-pressure gas transmission pipeline which would connect to the existing Moomba to Sydney pipeline. (GHD, 2017, p. ES.1)*

On 15 May 2018 Santos Managing Director and Chief Executive Officer Kevin Gallagher (2018, p. 17) told the 2018 APPEA that:

*In New South Wales, Santos has already committed to reserve all of the gas from the Narrabri Gas Project for the domestic market.*

In June 2018, Santos' head of onshore upstream projects David Banks wrote to the then NSW Labor Opposition energy spokesperson Mr Adam Searle advising that the development application specified that the Narrabri Gas Project was a domestic gas project and that Santos was willing to offer an undertaking to that effect (Macdonald-Smith, 2019). According to the letter:

*Santos would be agreeable to a condition of approval that required Narrabri gas to be sold to the domestic market and would be prepared to offer this to the Independent Planning Commission which is the consent authority for the project... (Macdonald-Smith, 2019)*

In late February 2019, Santos (2019a) announced that it had entered into a non-binding agreement with Perdaman for the supply of 14.5 PJ of natural gas per annum over 20 years, subject to a final investment decision for the Narrabri Gas Project. Under the agreement, gas would be supplied to a proposed new ammonium nitrate plant near Narrabri to produce fertiliser for agribusiness. The plant would be developed in parallel with the Narrabri Gas Project to use appraisal and early development gas.

In May 2019, Santos (2019c) announced that it had signed a non-binding memoranda of understanding with Brickworks and Weston Energy for the supply of natural gas from the Narrabri Gas Project. Under the proposed transactions, Santos would supply Brickworks with up to 3 PJ per year of natural gas from Narrabri for seven years from 2025 and Weston Energy with 10 PJ per year for 10 years, commencing no earlier than 2023. The supply of Narrabri gas would be subject to a final investment decision, negotiation and execution of a definitive gas supply agreement and approvals by each party.

Mr Gallagher (2019a, p. 1) told the 2019 APPEA conference on 30 May 2019:

*If it is approved, Santos has given an undertaking that 100 per cent of Narrabri gas will go to the domestic gas market.*

The average cost of production for gas in the Eastern Gas Region is currently \$2.91 per GJ and the current most expensive cost of production is \$4.90 per GJ from the Otway Basin in Victoria.<sup>11</sup> In addition, there are also 8 undeveloped projects in the Bowen and Surat Basins in Queensland each with gas resources of more than 1,000 PJ that collectively account for gas resources in excess of 53,000 PJ, with an average weighted production cost of \$5.91 per GJ. This compares to an estimated production cost of \$7.40 per GJ for the Narrabri Gas Project. The 8 undeveloped projects in the Bowen and Surat Basins would be a much more attractive and cost-effective proposition for the LNG export projects to have developed than the Narrabri Gas Project, even before consideration of transmission costs.

Santos' current assertions that all gas from the Narrabri Gas Project would be directed towards domestic gas users should not necessarily be taken at face value in light of previous claims it made that GLNG would not be diverting gas from local markets to export markets. However, the available evidence suggests that gas produced from the Narrabri Gas Project will be far too expensive to be of any interest for the LNG export projects. On this basis, Santos' claims that gas produced from the Narrabri Gas Project will be directed towards domestic gas users appears credible.

## 7. GAS PRICING IN THE EASTERN GAS REGION

### 7.1 Gas Supply Arrangements

The capital expenditure incurred in the development and construction phase forms a large proportion of the total costs of a natural gas development project. These projects are major investments in specific assets that cannot be readily redeployed for other purposes without a significant loss of productive value.

Asset specialisation creates openings for opportunistic behaviour in which parties can manoeuvre to extract wealth from the asset owner. Opportunistic behaviour has been described as the pursuit "self-interest with guile" (Williamson, 1979, p. 234n). A 'hold up' occurs where the party making an investment cannot be guaranteed to receive an adequate return from the project after the investment has already been made.

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

Similarly, the three LNG export projects entered into large long-term LNG export agreements to underpin their substantial investment in the development of their LNG export facilities (Australian Competition and Consumer Commission, 2016, p. 42).

Aside from GSAs, wholesale gas within the Eastern Gas Region can also be traded on a short-term basis through the Victorian declared wholesale gas market (DWGM), the Short Term Trading Market (STTM) operating in Sydney, Adelaide and Brisbane, and the Wallumbilla Gas Supply Hub (GSH) west of Brisbane and the Moomba GSH.

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<sup>11</sup> See Australian Energy Market Operator (2019).



## 7.2 Changes in Gas Prices

From the late 1970s until 2010, domestic gas production in the Eastern Gas Region had taken place in an environment of relatively low gas prices (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 13). Historically, natural gas prices in the Eastern Gas Region have been low by international standards (Australian Competition and Consumer Commission, 2016, p. 1). Until approximately 2010, new gas contracts were available in eastern Australia at price levels that had remained steady in real terms over the previous decade or longer (Jacobs SKM, 2014, p. 11). Domestic gas contract prices historically averaged around \$3-\$4 per GJ (Australian Energy Regulator, 2018a, p. 208).

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 was the Asian LNG market (Jacobs SKM, 2014, p. 11). A number of export projects were proposed between 2007 and 2008 and three projects commenced construction in 2011 and 2012 – QCLNG, GLNG and APLNG (Jacobs SKM, 2014, p. 12).

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

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

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

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

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

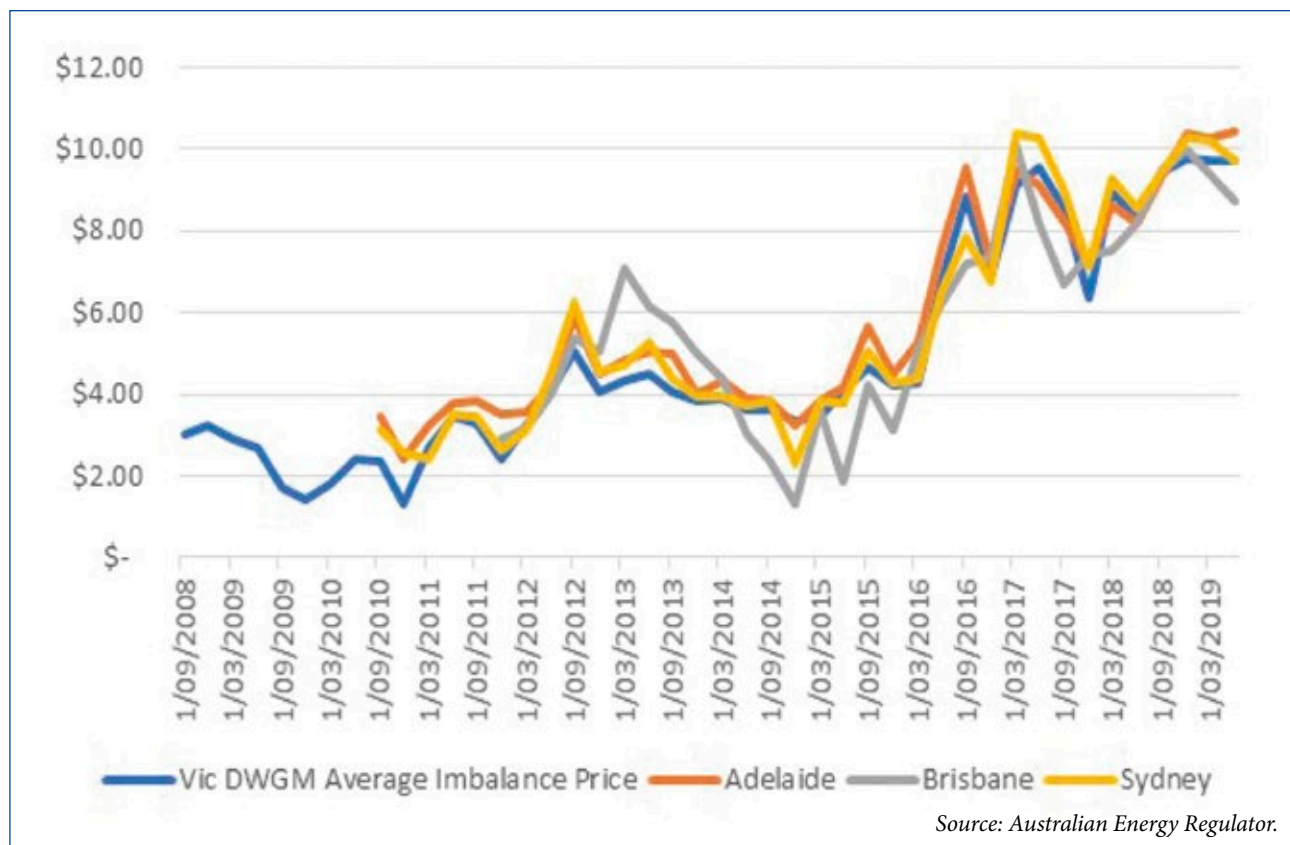
GSAs signed around 2015 were often for around \$6 per GJ; in late 2016 prices offered to industrial customers began to rise rapidly, peaking above \$20 per GJ in the first half of 2017 (The Australian Industry Group, 2018, p. 9). However, prices have since abated from these more extreme levels. By August 2018, most offers were priced at, or above, the mid-\$10 per GJ level (Australian Competition and Consumer Commission, 2018, p. 12). The latest data shows that the bulk of commercial and industrial gas users will be paying at least \$9 per GJ and some more than \$11 per GJ for gas in 2019 (Australian Competition and Consumer Commission, 2019, p. 9).

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

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

The rapid increase in the wholesale gas price from historical values of around \$3 per GJ to present prices of around \$10 per GJ since the three LNG export projects commenced operations in 2015 and Santos prioritised Cooper Basin production to GLNG is shown below in Figure 14 from the Victorian DWGM and the STTM prices in Sydney, Adelaide and Brisbane.

Figure 14: Quarterly Prices for the Imbalance Price for the Victorian Declared Wholesale Gas Market and the Short Term Trading Market Prices for Sydney, Adelaide and Brisbane (\$ per GJ)



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

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

While the option for southern gas producers of selling gas to the LNG export projects remains, the price they can achieve from selling to the LNG export projects represents the floor price in their negotiations with domestic gas buyers (Australian Competition and Consumer Commission, 2016, p. 51). Given the lack of alternative southern producers that are able to offer significant volumes of uncontracted gas, a buyer's alternative in the negotiation with the GBJV is likely to be uncontracted gas available in Queensland. Given the Queensland market is now being driven by the LNG fundamentals, southern buyers would have to offer the LNG netback price at Wallumbilla to northern producers to bid this gas away from the LNG projects and then transport this gas to their location. This price generally represents the ceiling in a buyer's negotiations with the GBJV. In this regard, the ACCC (2019, p. 41) has noted the Victorian gas producers (Gippsland, Bass and Otway basins) received higher prices at the end of 2018 than other gas producers in the Eastern Gas Region.

## 8. CAN THE NARRABRI GAS PROJECT LOWER GAS PRICES?

### 8.1 Claims of Lower Gas Prices

Claims have previously been made that developing NSW's CSG resources would put downward pressure on gas prices. In turn, this would have flow on effects for the cost of GPG leading to lower electricity prices. In its submission to the NSW Legislative Council Select Committee on the Supply and Cost of Gas and Liquid Fuels, energy company AGL (2014, p. 4) claimed:

*NSW has ample resources in the form of CSG that can be safely developed with appropriate environmental protections to restore energy security and to place downward pressure on prices.*

According to Edward Boyd (2019), NSW Political Reporter for *The Daily Telegraph*:

*There is a plentiful energy source available in NSW that could help slash electricity bills for households across the state – but both major parties refuse to give it the green light.*

*Experts say if coal seam gas (CSG) mining is harnessed to unlock the untapped potential of NSW, wholesale gas prices could be slashed from about \$10 per gigajoule to \$5 – a price point which makes gas-fired power generation a more attractive prospect.*

*This in turn would bring down electricity prices, benefiting the hardworking people and businesses of the state.*

Dr Graeme Bethune, Chief Executive Officer of energy advisory firm EnergyQuest has argued that if large-scale gas development occurred across NSW then wholesale gas prices would be cut in half:

*Gas prices would be lower than they are now, the market wouldn't be tight. If there was large scale development prices would probably be more like \$5 a gigajoule rather than \$10 gigajoule.*

*Lower gas prices in NSW would help take the pressure off electricity prices. However, this requires large-scale gas development in NSW. (Boyd, 2019)*

According to Credit Suisse analyst Saul Kavonic:

*The Narrabri project can help bring on more supply and would likely result in some lower cost gas made available to manufacturers to support manufacturing jobs.*

*But further new gas supply developments would be needed ... in order to structurally lower gas prices across NSW for all users. (Boyd, 2019)*

However, the Independent Pricing and Regulatory Tribunal (IPART) has expressed a contrary opinion. According to IPART (2014, p. 2), the development of the three LNG export projects means the Eastern Gas Region has become linked to global LNG markets with prices to adjust to world prices as a consequence:

*For the first time, the ability to export liquid natural gas (LNG) means that gas reserves previously supplied to NSW are being directed through Gladstone (in Queensland) for export. Eastern Australia is becoming part of a single global market for commodity gas, and wholesale prices are being increasingly set by international prices. In the future, it is likely that NSW gas retailers will have to compete with offshore demand and pay export parity prices for wholesale gas.*

In turn, IPART (2015, p. 2) has expressed scepticism as to whether the development of CSG projects in NSW is likely to have a bearing at all on gas prices in NSW:

*It is unclear how the development of coal seam gas reserves in NSW might affect domestic gas prices. At least in the short term, NSW would still be a small supplier in the context of the world gas market. In our view many other factors, for example domestic and international gas demand and the availability of LNG export capacity, would have a bigger impact on the price of gas in NSW.*

## 8.2 Determinants of Wholesale Gas Prices in New South Wales

### 8.2.1 Current Marginal Source of Supply

According to the Chair of the ACCC, Mr Rod Sims (2019):

*The level of future domestic prices in the southern states will depend on the marginal source of supply in the southern states.*

Ofgem (2016, p. 12) (the Office of Gas and Electricity Markets), the energy regulator in the United Kingdom, has described the role of the marginal source of supply in setting wholesale prices in the following terms:

*In a competitive market wholesale prices are based on the cost of the marginal source of supply. This is the final source of gas or electricity supply needed to meet demand. What makes up the marginal source of supply will vary depending on what supplies are available, the costs of those supplies, and the level of demand.*

The ACCC (2018, p. 82) commissioned energy consultants, the Core Energy Group, to determine the marginal source of supply in the Eastern Gas Region. This is the final source of gas supply needed to meet demand, which the Core Energy Group has defined as the supply region connected to the Eastern Gas Region with the highest forward cost – where material uncontracted gas reserves are expected to be in production in 2019. The highest cost of supply regions that meet this criteria are in the Surat Basin, which include 9260 PJ of 2P reserves with a forward production cost of \$5.55 per GJ.

The marginal source of supply estimated by the Core Energy Group plus the current published transmission costs from the Wallumbilla Gas Supply Hub to Sydney of \$2 per GJ (APA Group, 2019a) provides a delivered cost of gas

to Sydney of \$7.55 per GJ. This compares to a delivered cost to Sydney of \$9 to \$9.40 from the Narrabri Gas Project. Under these circumstances, gas supplied from the Narrabri Gas Project, even if it could be made available before the end of 2019, would be unlikely to influence, let alone reduce gas prices, as it would not represent the marginal source of supply for NSW.

Furthermore, given there are 22 undeveloped gas projects with lower estimated production costs than the Narrabri Gas Project, it is likely to take a long time before there is sufficient movement up along the supply curve to the point where the Narrabri Gas Project becomes the marginal source of supply. By such time, another marginal source of supply may have presented itself.

## 8.2.2 Future Marginal Source of Supply

In the face of declining gas production in the southern states and the possibility of restricted gas supply from Queensland due to limited available CSG production and pipeline infrastructure constraints, there are currently proposals for the construction of five LNG import terminals in the southern states. All of the proposed LNG import terminals intend to utilise Floating Storage Regasification Unit (FSRU) technology.

A FSRU is essentially a floating LNG import terminal. The FSRUs and onshore LNG import terminals both take up LNG, regasify it by taking it from a liquid and expand it back into a gas (Mishra, 2018). The FSRUs are custom-built vessels, similar to LNG tankers but with an ability to transform LNG back to the gaseous state. Both facilities, the LNG import terminals and FSRUs, need a berth for the LNG ship, storage tanks and pipelines.

While onshore LNG terminals can take between 5 and 7 years to plan, construct and bring online, FSRUs require little construction or investment, can provide access to LNG much faster, and cost less than half the cost of an onshore facility (Mishra, 2018). Most FSRUs are leased as the vessel is owned by a shipping company and can be reassigned on project completion (Songhurst, 2017, p. 33). This provides a major advantage over onshore LNG import terminals where the construction cost represents a sunk cost.

In August 2017 AGL (2017) announced Crib Point on Western Port Bay near Hastings in Victoria as the preferred site for its FSRU and pipeline to supply customers in south eastern Australia. AGL (2019a) expects the first gas to be delivered from the proposed terminal in the first half of 2023 and the Victorian Government is currently undertaking an Environment Effects Statement (EES) process to assess the project.

In December 2018 the South Korea-based Energy Projects and Infrastructure Korea or EPIK Co. Ltd. (EPIK) (2018), an LNG FSRU project development company, announced that it has entered into a Project Development Option Agreement with the Port of Newcastle to commence preliminary works on a proposed LNG FSRU import terminal. According to Jee Yoon, EPIK's Managing Director:

*Based on our assessment of the New South Wales gas market, particularly along coastal demand regions such as Newcastle and Sydney, we are confident that by importing LNG via a new, low cost FSRU terminal, we will be able to provide an infrastructure solution that is capable of delivering a cost-efficient source of alternative gas supplies to the region on a long-term basis.*

In April 2019 Australian Industrial Energy (AIE) (2019), a joint venture between Andrew Forrest's Squadron Energy; global energy infrastructure investor Marubeni Corporation (Marubeni) and the world's largest buyer of LNG, JERA Co. Inc. (JERA), received planning approval from the NSW Government for an LNG import terminal at Port Kembla known as the Port Kembla Gas Terminal (PKGT). With a forecast capital cost of between \$200 – \$250 million, PKGT, once constructed and operational, is expected to be able to supply up to 100 PJ of natural gas per annum. Santos' partner in the Narrabri Gas Project EnergyAustralia has signed a preliminary agreement for a five-year gas supply contract to take 15 PJ per annum for its residential and industrial customers as well as for electricity generation, with AIE commencing supply on 1 January 2021 (Australian Industrial Energy and EnergyAustralia, 2019).



According to the then AIE chief executive James Baulderstone in July 2018:

*The terminal will be able to source the world's cheapest LNG at a fraction of the capital required for new local supply. It can also supply almost three times the volume of planned NSW development in a much quicker time period. (Williams, 2018)*

Venice Energy (2019) is proposing to construct an LNG terminal in the Outer Harbour at Port Adelaide. Venice Energy is currently finalising its development application and anticipates that it will receive all government and regulatory approvals before the end of 2019, with construction likely to commence in the first quarter of calendar year 2020 and commissioning by the end of that year. The terminal will be capable of delivering up to 120 PJ of gas on an annual basis.

In June 2018 it was reported that ExxonMobil was also considering a potential LNG import terminal that could bring additional supply into Victoria and the Eastern Gas Region (Chamber, 2018). However, it is understood that ExxonMobil has not yet settled on a site for the terminal.

According to Santos Managing Director and Chief Executive Officer Kevin Gallagher:

*Import terminals are not the answer. The only way to have an energy advantage over other countries is to put in place strict environmental standards so you can safely produce as much of your own energy resources as you can at as low a price as you can.*

*Importing gas will lead to higher prices or shortages, particularly when LNG demand in Asia is high. It is a certain way of ensuring that at some time in the future foreign suppliers would have a gun to the head of Australian manufacturers. (Santos Ltd, 2019b)*

On the other hand, NSW Deputy Premier John Barilaro commented in response to claims from Santos that the Narrabri Gas Project would always provide cheaper gas than LNG imports:

*In the current market, it is more cost-effective to import gas into the state of NSW than to source it locally or interstate. (Macdonald-Smith, 2019b)*

The LNG export projects in the Eastern Gas Region have long-term contracts with buyers in Asia, where LNG prices are linked to the price of Japan Customs-cleared Crude (JCC) oil (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 99). This price is closely linked to the price of Brent (European) crude oil prices, a heavily traded crude oil price marker (Jacobs SKM, 2014, p. 17).

In contrast, prices in LNG spot and short-term markets usually depend on supply and demand for LNG (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 99). Where short-term contracts are oil-linked, these contract prices are currently being signed at a discount to the oil-linked LNG contract prices received by the Queensland LNG export projects. This may mean that LNG could be imported into the southern gas market on a spot or short-term basis at a lower price than Queensland LNG is being sold on long-term oil-linked contracts.

There are a number of reasons why LNG imports might be competitive with pipeline imports from Queensland (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 100). First, the cost of production in Queensland is relatively high. The vast majority of the gas produced in Queensland is CSG where production requires drilling hundreds of new wells per year — something that conventional gas production does not require — which adds to the cost of production. Gas in many other parts of the world — be it US shale gas or conventional gas in Qatar or off Australia's North West coast — has lower production costs.

Second, transporting gas via pipeline from Queensland to the southern market is relatively costly (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 100). The current published transmission costs from Wallumbilla to Sydney or to Culcairn for further transmission into Victoria is \$2 per GJ (APA Group, 2019a). On the other hand, it has been estimated that the costs per GJ of regasification for an FSRU

importing up to 100 PJ per annum could be in range of between \$0.80 – \$1.30 per GJ (Department of Industry, Innovation and Science – Office of the Chief Economist, 2018a, p. 105).

LNG spot prices have declined dramatically since late 2018, even falling through the 2018–19 northern hemisphere winter — a time of the year at which prices would usually spike, due to strong seasonal demand (Department of Industry, Innovation and Science – Office of the Chief Economist, 2019, p. 54). The price fall has been driven by the delivery of new capacity in the US, Australia and Russia combined with declining imports in Japan and South Korea — the world's largest and third largest LNG buyers. The recent fall in LNG spot prices means that they have now diverged substantially from long-term oil-linked contract prices.

In 2019 and 2020, further additions to global supply capacity are expected to outstrip growth in LNG demand (Department of Industry, Innovation and Science – Office of the Chief Economist, 2019, p. 54). Consequently, the Commonwealth Department of Industry, Innovation and Science is forecasting Asian LNG spot prices to remain low, averaging the equivalent of A\$7.60 per GJ in 2019, and A\$8.80/GJ in 2020 — well down on the 2018 average of A\$12.40 per GJ. In 2021, LNG spot prices are expected to recover slightly to A\$10.70/GJ. Similarly, while the World Bank (2019, p. 17) is forecasting a modest recovery in LNG prices from their current lows, it is not forecasting a return to recent 2018 highs any time soon.

The AEMO (2019, p. 3) has arrived at a mixed assessment of the benefits of LNG import terminals in the Eastern Gas Region:

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

However, according to Dr Graeme Bethune, Chief Executive Officer of energy advisory firm EnergyQuest:

*There are fears that such projects will lock the east coast into international gas prices but that has happened already.*

*What will lock the east coast into even higher gas prices, however, are restrictions on new supply, LNG imports and exploration.*

*Developing LNG import terminals sooner rather than later would be a prudent form of risk mitigation. (Latimer, 2019)*

According to Nicholas Browne, Director of Gas and LNG Research at energy consultants Wood Mackenzie:

*We definitely would see a rationale for one terminal to give another source of gas into the east coast market. We think one terminal would be sufficient till the mid to late 2020s. (Paul, 2019)*

If imported gas, namely LNG, becomes the marginal source of supply, then wholesale gas prices will be set to import parity levels in order to attract the supply of gas required to meet demand. If imported gas (i.e. LNG) becomes the marginal source of supply for the Eastern Gas Region, then gas producers selling to domestic gas users will receive an import parity price for their product. Under these circumstances, the Narrabri Gas Project will not provide the marginal source of supply for wholesale gas in NSW, and is thus unlikely to exert any influence over wholesale gas prices in NSW over the longer term.

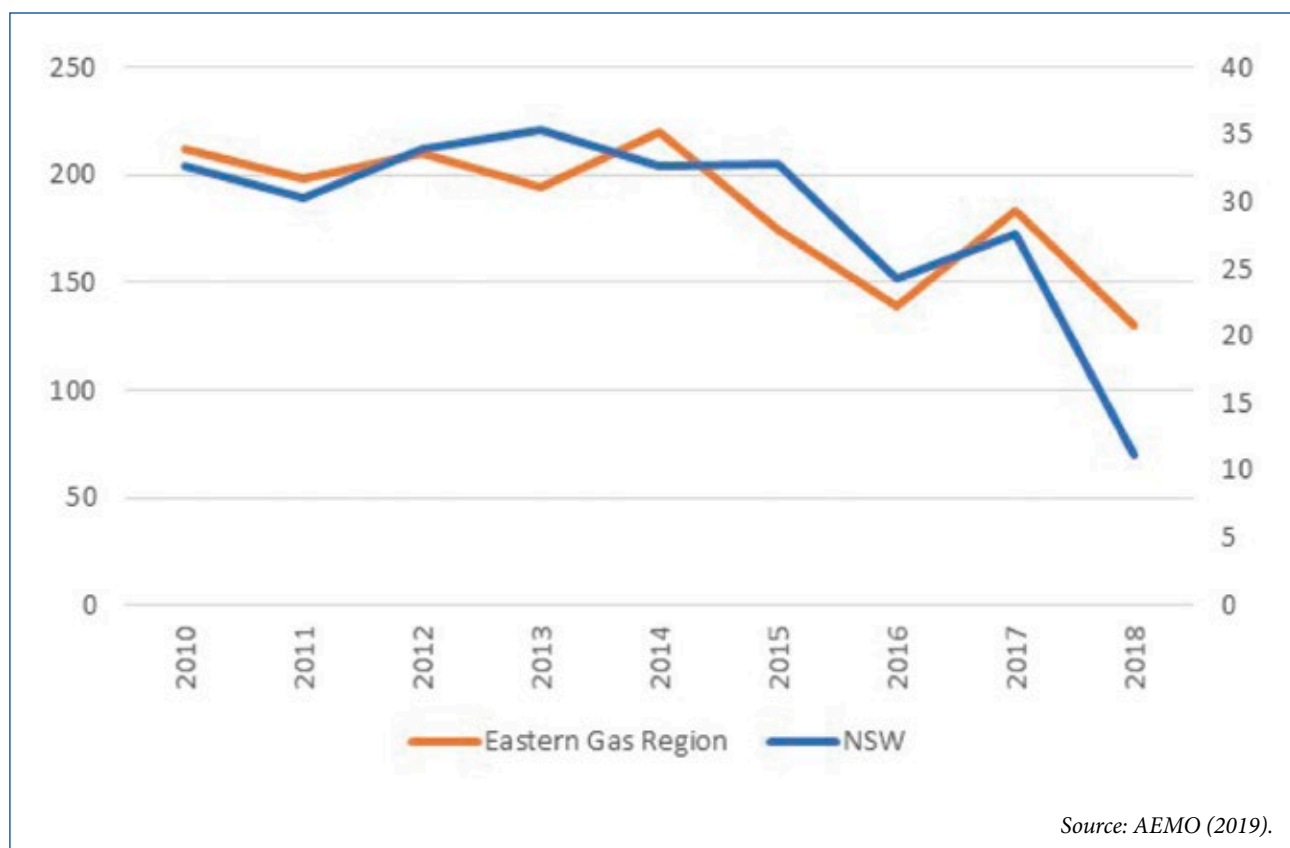
### 8.3 Would the Narrabri Gas Project Deliver Lower Electricity Prices?

The National Electricity Market (NEM) covers eastern and southern Australia, similar to the Eastern Gas Region. Traditionally, GPG has been used to meet periods of high demand in the NEM, such as when air conditioning loads are high on hot summer afternoons (Finkel, Moses, Munro, Effene, & O'Kane, 2017, p. 206).

However, the NEM became more reliant on GPG during 2017 following the closure of several coal fired generators in 2016 and 2017 (Australian Energy Regulator, 2018a, p. 182). On 9 May 2016 the 240 megawatt (MW) brown coal fired Playford B Power Station and the 546 MW brown coal fired Northern Power Station co-located at Port Augusta in South Australia ceased electricity generation (Australian Energy Market Operator, 2018). Then at the end of March 2017 the 1,600 MW brown coal fired Hazelwood Power Station in the La Trobe Valley in Victoria ceased electricity generation (Australian Energy Market Commission, 2018, p. 11).

Increased output from gas generators in Victoria and South Australia and black coal generators in NSW and Queensland was required to replace the output of Hazelwood during 2017 (Australian Energy Regulator, 2018, p. 1). The increase in demand from GPG during 2017 temporarily abated a long-term decline in demand. This is outlined in Figure 15 below. The AEMO (2019, p. 26) is forecasting that gas consumption from GPG will continue to decrease from recent historical levels, as new renewable electricity generators are forecast to be installed in the NEM.

Figure 15: Gas Consumption by Gas Powered Generation in the Eastern Gas Region and NSW – 2010 to 2018 (PJ)



GPG typically sets the spot price for the wholesale electricity market when variable renewable energy (VRE) generation is low or demand is high, and this flows through to consumers as higher electricity prices (Finkel, Moses, Munro, Effeney, & O’Kane, 2017, p. 6). In turn, gas has now become a major influence over electricity prices as GPG has become the marginal source of supply for electricity generation. According to the ACCC (2017a, p. 20):

*... the rising cost of gas is one of the likely drivers of Australia’s current electricity affordability issues, which is also currently being examined by the ACCC in our retail electricity inquiry. GPG is increasingly the marginal source of electricity generation, and so the prices being faced by GPG are a crucial input into electricity prices. The projected gas supply shortfall will impact on those*

*GPG which do not have long-term supply contracts, which may mean greater reliance on domestic spot markets, potentially impacting on the supply and cost of peak generation.*

Similarly, according to Christopher Flynn and Emily Tsokos (2017, p. 36) from law firm Gilbert + Tobin:

*The critical role of gas-fired generators as the marginal source of [National Electricity Market] supply at times of peak demand means that any inefficiency in gas markets may well spill over into the [National Electricity Market].*

A major factor behind rising wholesale electricity prices has been the significant shortages in competitively priced gas at a time when GPG would often be the logical source of replacement for lost coal-fired capacity (Australian Competition and Consumer Commission, 2018c, p. viii). Gas prices have doubled or tripled in recent years. The ACCC has estimated that for every \$1 per GJ rise in gas prices, the wholesale price of electricity rises by up to \$11 per megawatt-hour (MWh), depending on regional differences in the NEM.

It is highly unlikely the development of the Narrabri Gas Project will do anything ease electricity prices in the NEM. This is because the project will not have any bearing over gas prices in the immediate future or over the longer term as the project is unlikely to ever represent the marginal source of supply for gas in the Eastern Gas Region. In turn, the impact of the Narrabri Gas Project over wholesale gas prices in the Eastern Gas Region is likely to be negligible, and will thus exert little if any influence over prices for GPG in the NEM.

#### 8.4 Would the Narrabri Gas Project Relieve Gas Price Cost Pressures on Manufacturers?

The manufacturing sector is involved in transforming materials, substances, or components into new products (Australian Energy Market Operator, 2019, p. 24). Key industries in this sector that consume relatively large volumes of gas include basic chemical manufacturers, primary metal manufacturers, food manufacturers, and mining.

Gas, as part of Australia's energy mix and as a direct business input, has provided a competitive advantage to Australia's manufacturing sector and broader economy for decades (Australian Workers' Union, 2017, p. 4). Cheap energy has previously underpinned the international competitiveness of the manufacturing sector Australia-wide.

However, the skyrocketing price of formerly cheap domestic gas supplies since the price was exposed to export LNG markets has put swathes of local manufacturing industry in danger (Editorial, 2019). While wholesale gas prices in the Eastern Gas Region have dropped from the extreme levels over \$20 per GJ seen in early 2017, they are still three times or more higher than historical tariffs of \$3-\$4 per GJ, forcing the closure of several manufacturing plants this year (Macdonald-Smith, 2019).

Two manufacturers have already gone into administration citing rising gas prices as one of the contributing factors. In January 2019 RemaPak, a Sydney-based producer of polystyrene coffee cups, and in March 2019 Claypave, a Queensland-based brick and paving manufacturer, went into administration with both companies citing rising gas costs as an important contributing factor (Sims, 2019). RemaPak was paying wholesale gas prices as high as \$16 per GJ (Macdonald-Smith, 2019c). In late May 2019, Dow Chemicals announced that it had closed its manufacturing plant at Altona in Melbourne citing rising gas prices and increasing international competition as factors in its decision (Toscano & Sakkal, 2019).

Manufacturers have expressed concerns that they cannot pass on their gas cost increases to their customers because they would become uncompetitive with their overseas competitors who are not exposed to rising gas prices in their domestic markets (Australian Competition and Consumer Commission, 2018a, p. 62). Instead, these users must absorb higher gas costs, unless they can use other strategies to mitigate the effects.

There have been warnings from several parties that continuing high gas prices threaten the future viability of Australian manufacturers reliant on gas. At the end of last year, the Chief Executive of the Australian Industry Group, Innes Willox, warned:

*Continuing higher gas prices are a major threat to the viability of a wide variety of Australian industries as well as to household budgets. (The Australian Industry Group, 2018a)*

In late May 2019 the Chair of the ACCC, Mr Rod Sims (2019), warned:

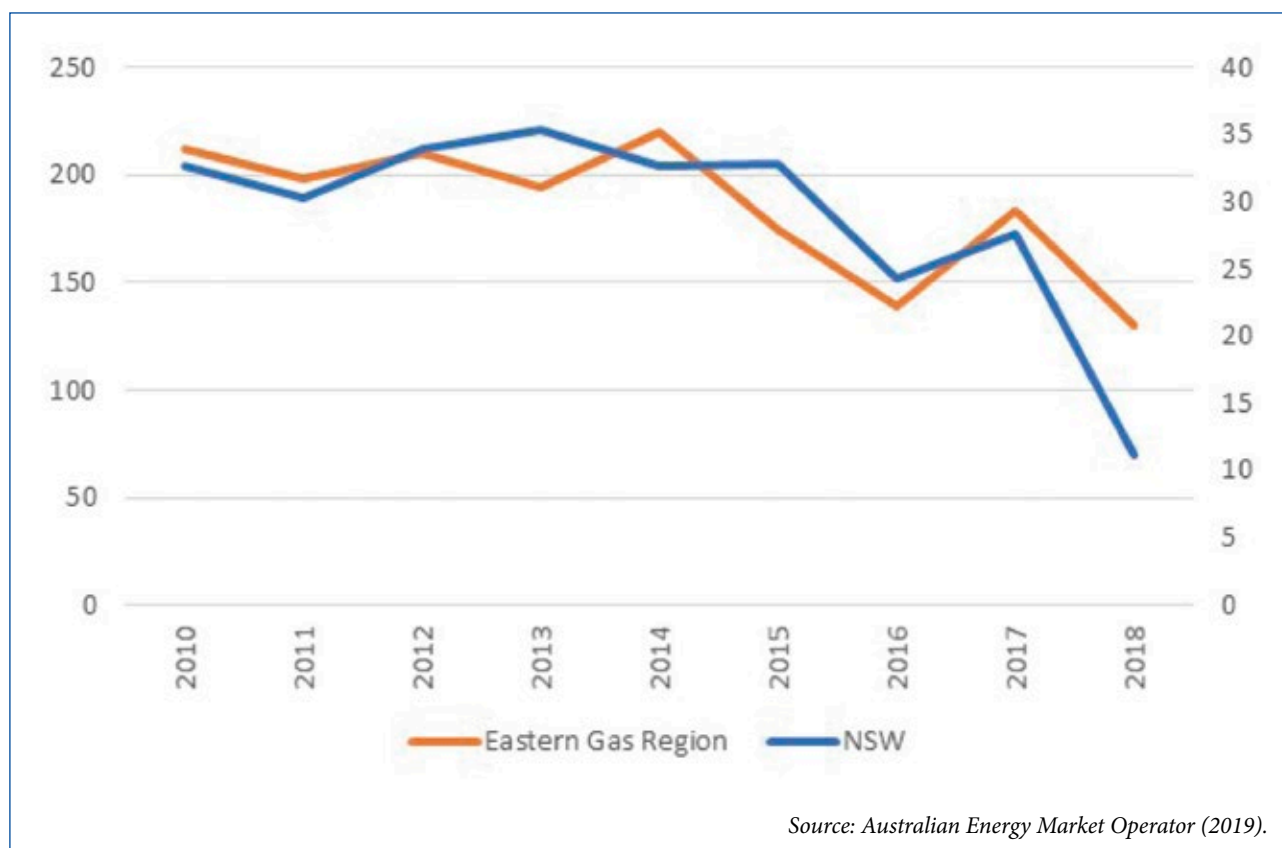
*Domestic wholesale gas prices have risen two to three times higher than historical prices in a relatively short period, putting many trade-exposed Australian manufacturers under extreme pressure to remain internationally competitive.*

In June 2019 Weston Energy Managing Director Garbis Simonian has warned:

*Unless we can find a sensible solution to our energy crisis, then all that's going to happen is we are going to price our manufacturing industries out of Australia. They are going to go and set up in Asia and we are going to lose jobs. (Toscano, 2019)*

In response to rising gas prices, gas consumption by industrial users (largely made up of manufacturers) both in NSW and in the Eastern Gas Region has declined, as outlined in Figure 16 below.

Figure 16: Annual Gas Consumption by Industrial Users in the Eastern Gas Region and New South Wales – 2010 to 2018 (PJ)



According to Stephen Bell, chief executive of Qenos, the sole manufacturer of polyethylene and polymers within Australia, wholesale gas prices in the range of \$10 to \$15 per GJ were not sustainable for them, and that:

*Large industrials like us need gas at \$6-\$8. (Macdonald-Smith, Weaker LNG outlook may cut local price, 2019a)*



It is highly unlikely the development of the Narrabri Gas Project will do anything to ease cost pressures facing manufacturers for several reasons. In the first instance, the project will not have any bearing over gas prices in the immediate future or over the longer term as it is unlikely to ever represent the marginal source of supply for gas in the Eastern Gas Region. In turn, the impact of the Narrabri Gas Project over wholesale gas prices in the Eastern Gas Region is likely to be negligible.

Second, even if the Narrabri Gas Project was developed, it would have production costs in the order of \$7.40 per GJ and a delivered cost of gas to Sydney in the order of \$9 to \$9.40 per GJ, that is a far cry from the \$6 to \$8 per GJ demanded by manufacturer Qenos.

Overall, the Narrabri Gas Project is unlikely to ease cost pressures from higher gas prices facing manufacturers.

## 9. CONCLUSIONS

Santos and the Santos-led GLNG project have been significant contributors toward any impending gas shortfalls in the Eastern Gas Region, as GLNG did not possess sufficient gas resources to justify its investment decision for a second LNG train. In turn, they have diverted substantial volumes of gas from domestic users through third-party gas supply contracts to satisfy their export contracts, contrary to previous claims that they would not.

Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its Narrabri Gas Project, without acknowledging the central role it played in creating the circumstances that it claims the Narrabri Gas Project will help to alleviate.

While the development of the Narrabri Gas Project will provide additional gas supply for NSW, there are plenty of cheaper gas resources that could be developed and it is unlikely to have any bearing over gas prices either in the immediate future or over the longer term.

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