Ledesma, David; Henderson, James; Palmer, Nyrie

Working Paper

The future of Australian LNG exports: Will domestic challenges limit the development of future LNG export capacity?

OIES Paper: NG, No. 90

Provided in Cooperation with:
The Oxford Institute for Energy Studies, Oxford

Suggested Citation: Ledesma, David; Henderson, James; Palmer, Nyrie (2014) : The future of Australian LNG exports: Will domestic challenges limit the development of future LNG export capacity?, OIES Paper: NG, No. 90, ISBN 978-1-78467-008-5, The Oxford Institute for Energy Studies, Oxford,
https://doi.org/10.26889/9781784670085

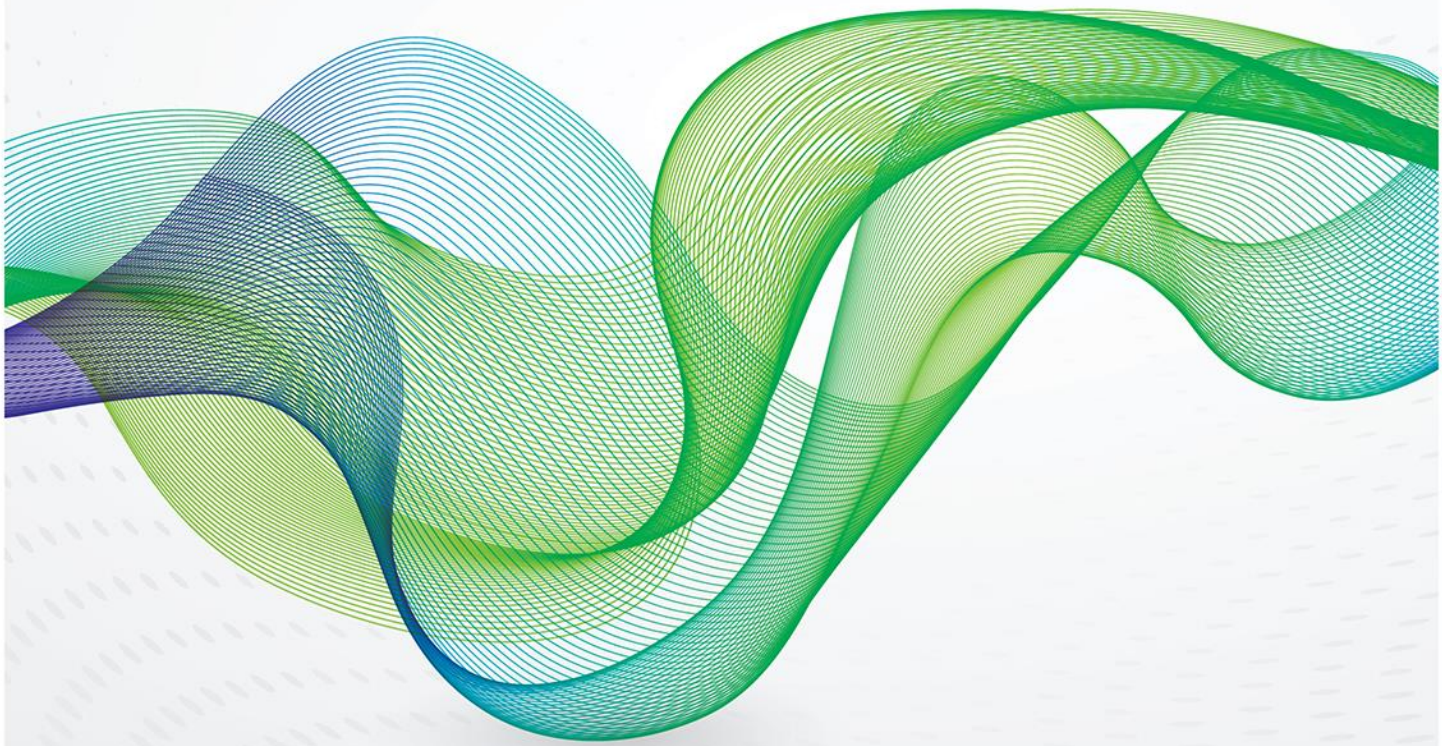
This Version is available at:
https://hdl.handle.net/10419/246524

THE OXFORD INSTITUTE FOR ENERGY STUDIES

September 2014

The Future of Australian LNG Exports:

Will domestic challenges limit the development of future LNG export capacity?



David Ledesma, James Henderson* & Nyrie Palmer**

OIES PAPER: NG 90

*Senior Research Fellows, OIES, **Senior Regulatory Officer, NSW Resources and Energy

The contents of this paper are the authors' sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its members.

ISBN
978-1-78467-008-5

Acknowledgments

The authors would like to thank everyone who helped us in drafting the paper, in Australia as well as the UK. Your contributions have helped to enrich the document and ensure accuracy of the content and conclusions

Preface

With seven the new LNG projects under construction and due for completion in the 2014 – 2018 timeframe amounting in addition to existing facilities, Australia is expected to overtake Qatar as the world's largest supplier of LNG by the end of the 2010s. With its plentiful gas reserves, prior track record of LNG project execution and operation and relative proximity to the fast growing Asian LNG markets the degree of comparative advantage would seem to guarantee a benign investment environment.

However, several factors, among them competition for skilled labour within Australia, the strength of the Australian dollar and the specific logistical and environmental sensitivities of the project locations have resulted in significant cost escalations and in some cases delays to the original project schedules. This paper also serves to convey an understanding of the much overlooked Australian gas market and, significantly the impact that the new LNG projects are already having on internal supply/demand – price dynamics and the political challenges raised.

Much energy media attention has focused on the problems faced by the current group of new Australian LNG projects. This paper comprehensively addresses the root causes but more importantly conveys the scale of the new wave of Australian LNG supply and integrates this with its impact on the domestic market which until now has been largely isolated from global energy dynamics. The OIES Natural Gas Research Programme is committed to producing timely and insightful research on both supply and demand side developments and this paper achieves both these objectives.

Howard Rogers

Oxford, September 2014

Contents

Figures

Tables and Maps

1. Overview

By 2018 Australia will become the largest LNG exporter globally with an aggregate of 86 mtpa LNG liquefaction capacity, with 67% based on the development of conventional gas reserves offshore the north and north-west of the country through three existing and three new land-based plants, while a further 4% (one facility) will use floating LNG technology. The balance (29%) will use unconventional (coal seam) gas as feedstock to three plants on the east coast on Gladstone Island. The six land-based liquefaction plants currently under construction, with a combined capacity of 58 mtpa, have all faced cost, environmental and timing challenges. That said, they are all expected to be operational by the end of the decade. The three coal seam gas projects on the east coast however may face continued feed-gas operational issues and possible shortages after start-up and, due to the nature of coal seam gas developments, new wells will have to be continually drilled throughout the life of the projects[1]. The probable need to supplement upstream feed-gas supply with 'grid-sourced' gas will impact on the east coast domestic gas market, where the price of gas has risen sharply over the past two to four years, as well as becoming less readily available under long-term contracts, even before the LNG export projects start production. This has led to lower domestic demand expectations and to some consumer groups calling for a gas reservation policy, or some similar review of exports, to keep gas available to the domestic market and hence keep gas prices down. In Western Australia there is a domestic market obligation (DMO), but domestic gas prices are also rising towards LNG export net-back parity levels, while in the Northern Territory, there is little or no political will to introduce a gas reservation policy,[2] despite the fact that a major recent industrial plant closure has been blamed to some extent on lack of gas availability.[3]

This paper, authored by two UK-based and one Australia-based researcher, will review the existing status of LNG projects that are in operation, before examining the seven new projects that are under construction and the reasons why these projects have experienced cost overruns and delays. The paper will then examine the domestic market in the west and north of the country, before focusing primarily on the markets in the east of the country. It will analyse the domestic debate over the potential balance of gas exports versus domestic use, covering issues such as the increasingly close relationship between LNG export volumes and prices, the outlook for future gas demand, the environmental debate over unconventional gas and the differing political priorities of the federal and regional governments. The paper will conclude by looking forward at the factors, both international and domestic, that will determine the extent and pace of new Australian LNG capacity to be constructed and discuss whether such projects will be able to find a place in an increasingly competitive global LNG market given the various political, commercial and economic challenges. Finally the authors will examine whether, in extremis, domestic politics and gas demand could result in no significant new Australian LNG capacity build.

[1] i.e. because of rapid well production decline rates.
[2] http://gastoday.com.au/news/nt_says_no_to_gas_reservation/081167/
[3] http://www.engineeringnews.co.za/article/nt-govt-urged-to-review-gove-gas-decision-2013-07-31

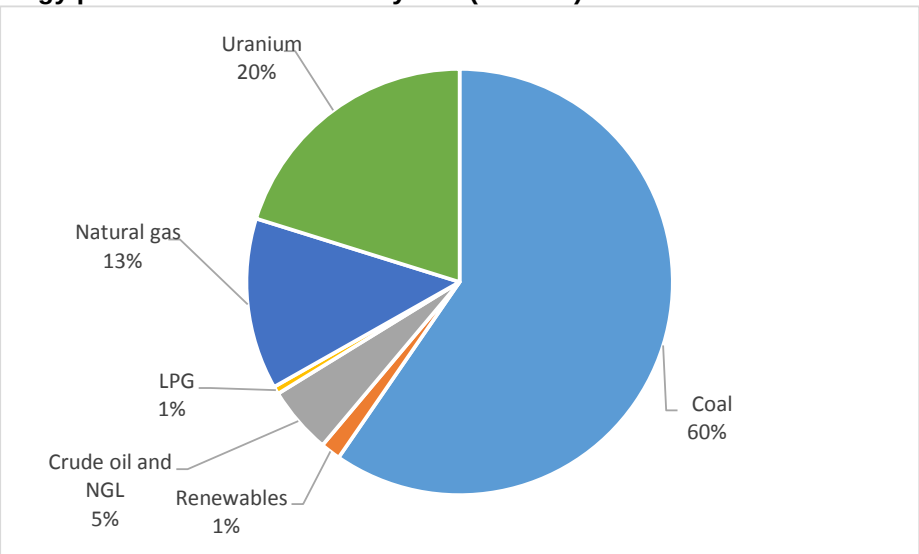
2. LNG in Australia

2.1 Introduction

With three existing LNG projects already providing over 24mtpa of LNG export capacity, and with a further seven schemes under construction, Australia's LNG export capacity is expected to exceed 85mtpa by 2018, at which point it will become the world's largest LNG exporter (due also to Qatar's continued moratorium on new developments). The additional development of over fifteen potential new Australian projects, (expansions and new greenfield schemes), could take the country's total LNG export capacity as high as 150mtpa beyond the end of this decade,[4] based not only on conventional onshore and offshore reserves but also on Australia's plentiful coal seam gas[5] (CSG) and shale gas resources. As such the outlook for Australian LNG exports would appear to be on a growth trajectory and with further room for expansion. However, the well-documented cost overruns and delays in many of the current developments, combined with an increasing domestic lobby focussed on rising gas prices and environmental issues, have coincided with growing indications of increased international competition in the global LNG market. Taken together, these factors have raised significant questions about the role of Australian LNG in the global gas market, and in this paper we examine the current debate and highlight the key issues that could determine its outcome.

However, although the gas industry in Australia is set for significant growth, it is important to note that its current contribution to the economy is relatively small when compared to the other commodities, which the country possesses in abundance. As shown in Figures 1 and 2, gas actually only accounted for 13% of total energy production in 2011/12, with coal and uranium taking the first two places, and its share of exports by energy content was even smaller at 8%.

Figure 1: Energy production in Australia by fuel (2011/12)



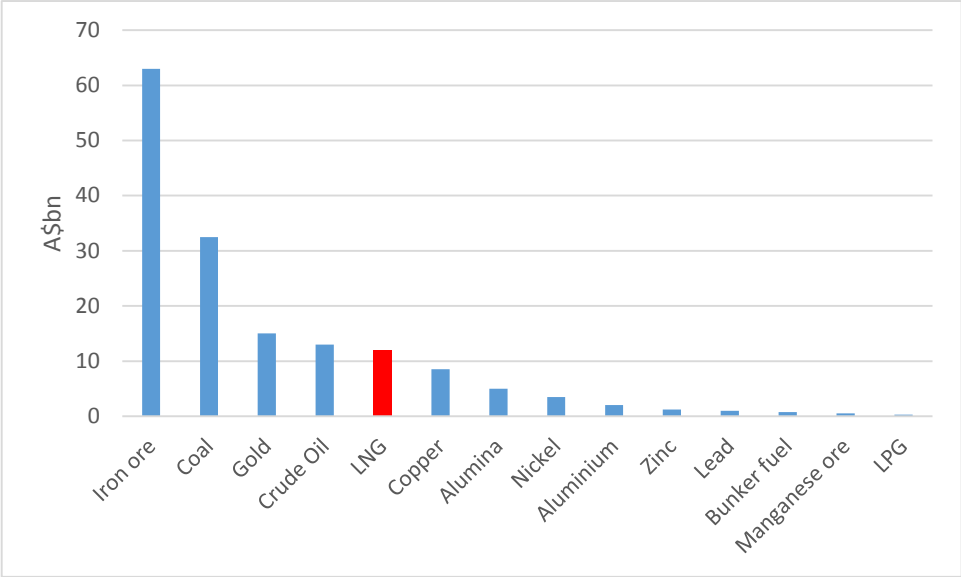
Source: Australian Bureau of Resources and Energy Economics

In terms of the broader economy, the impact of gas, measured in export revenues, is dwarfed by the contribution currently made by iron ore and coal (Figure 2), with LNG ranking fifth with a contribution of A$12 billion in 2011/12 compared to the A$63 billion brought in by overseas sales of iron ore. From

[4] BREE (2013a) p.31
[5] Coal Seam Gas, also known as Coal Bed Methane is methane which is held within the structure of the coal seams by adsorption. It may be produced in commercial quantities when the coal is de-pressurised and de-watered through drilling.

the perspective of GDP, oil and gas combined contributed approximately A$28 billion of value added in 2011/12, equivalent to only 2% of total GDP,[6] while the sector paid just under A$8 billion of taxes, or 4% of the total federal government revenue.[7] Meanwhile employment in the sector stands at 17,000,[8] compared to more than double that figure in the coal extraction industry. As will be noted later, this importance is expected to grow as new LNG projects start up and LNG exports increase.

Figure 2: Australia's major resource and energy exports by value (2011/12)



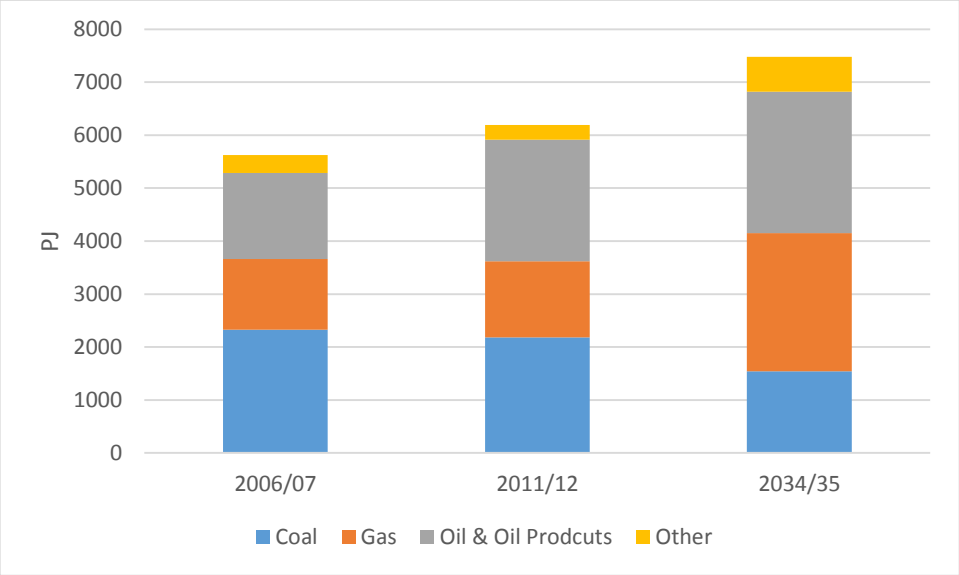
Source: Australian Bureau of Resources and Energy Economics

However, although the statistics concerning revenue generation and direct economic contribution suggest a limited current role for gas, the significant investment in the industry's expansion means that its political and economic role is set to expand rapidly. On the domestic front the current spending on LNG projects accounts for more than a third of all business investment in Australia, a figure which could rise to over 60% if all the proposed projects also go ahead (although as discussed later this is unlikely), while gas will also play an increasing role in providing energy for the country's other major industries. Furthermore, as the new LNG projects come online it is expected that the LNG sector will make a much larger contribution to export revenues, compensating for much slower anticipated growth in the exports of other commodities. As early as 2017/18 LNG export revenues are anticipated to reach A$62 billion, a more than five-fold increase over 2011/12 and moving LNG into third place behind iron ore and coal.[9] However, while this rapid expansion of export sales is taking place, gas is also expected to assume a much greater role in the domestic energy mix, with its share of total primary energy consumption forecast to rise from only 23% in 2011/12 to 35% by 2034/35. In combination with renewable energy it is expected to displace coal from the energy mix (Figure 3) as part of the government's drive to deliver reduced CO_2 emissions. Internationally, LNG will also help Australia's goal to establish itself as a more active participant in the Asia-Pacific region, as outlined in the government's 2012 white paper "Australia in the Asian Century",[10] providing the energy to support growth in countries such as China, Japan and Korea while also generating significant extra revenues

[6] Deloitte (2012) page v
[7] Ibid. p.ii
[8] BREE (2013b), p.8
[9] Deloitte (2012)
[10] Australia in the Asian Century (2012)

for its own economy. As a result, the ability of the Australian gas industry to develop sufficient resources at reasonable cost to satisfy both its domestic and export markets will be important for energy economies across the Asia-Pacific region.

Figure 3: Australian primary energy consumption by fuel



Source: Australian Bureau of Resources and Energy Economics

2.2 Australia's gas resources

According to the BP Statistical Review 2014 Australia contains 3.7tcm of proved gas reserves, and this figure corresponds with the 136Tcf (3.85tcm) of Economically Demonstrated Resources (EDR) identified by Geoscience Australia, of which 103Tcf (2.9tcm) is conventional gas and 33Tcf (0.9tcm) is to be found in unconventional fields. Table 1 shows the breakdown of resources, highlighting the fact that beyond the proved reserves base the country also contains significant upside from currently Sub-Economic and Inferred Resources, particularly in the areas of coal seam gas and tight gas (see Appendix 4 for full reserve definitions). Although not acknowledged yet by federal bureaux, Australia also contains very large potential shale gas resources, estimated by the recent EIA survey of global shale gas to be the seventh largest in the world at 437Tcf (12.4tcm).[11]

Table 1: Australia's total gas resources (bcm)

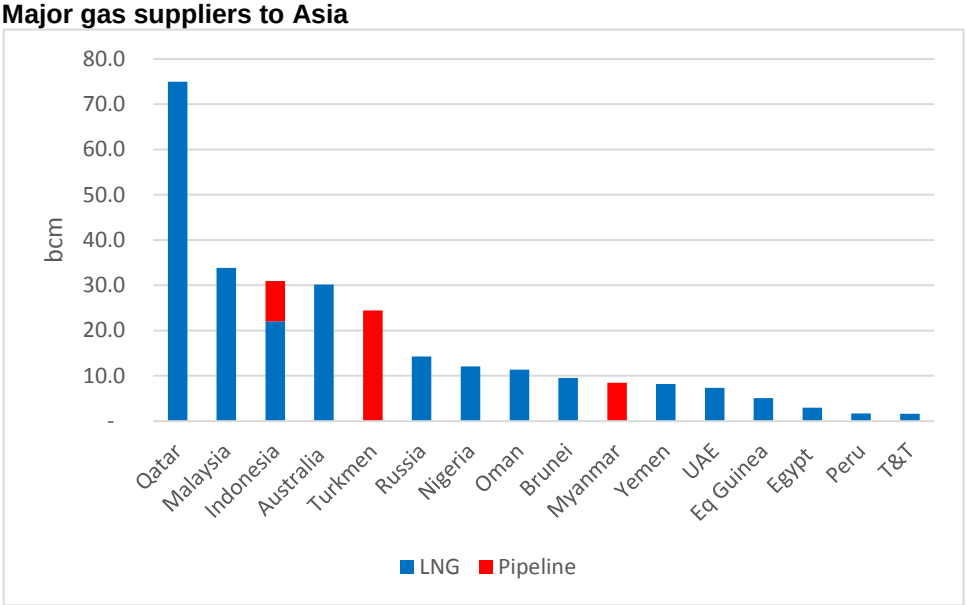
bcm	Nat Gas	CSG	Tight Gas	Shale Gas	Total
EDR	2920	925	0	0	**3845**
SDR	1535	1688	0	57	**3279**
Inferred	283	3142	568	0	**3994**
Total	**4739**	**5755**	**568**	**57**	**11118**

Source: Australian Bureau of Resources and Energy Economics

[11] EIA (2013) p.6

These figures, though large, only make Australia the 11th largest holder of gas reserves in the world, and, with 43bcm of output in 2013,[12] only the 13th largest producer. When placed in a regional context Australia's current relevance to the Asia-Pacific gas market becomes clear, as it is the fourth largest producer in the region (behind China, Indonesia and Malaysia), and perhaps more importantly is also the fourth largest supplier of gas to the major importing countries that are located there. Only Qatar, Malaysia and Indonesia (via LNG and pipeline) currently sell more gas to Asian customers than Australia, although Australia has now overtaken Indonesia as the third largest LNG exporter. However, as noted above, Qatar has made a political decision to impose a moratorium on expanding LNG export volumes above their current 77mtpa, due to potential geopolitical issues with Iran over the North Field, the view of the country's authorities that there is little need to generate extra revenues from LNG for such a small population and also a desire not to undermine prices in their existing markets.[13] Furthermore, the position of Indonesia and Malaysia as major exporters is starting to be eroded by their growing domestic demand for gas. As noted by the EIA, the Indonesian government is starting to take active measures to retain gas supply for the domestic market, and indeed the LNG liquefaction plant at Arun is being closed and being converted into a regasification plant for imports.[14] Meanwhile in Malaysia a regasification terminal has been constructed to satisfy growing domestic demand, and although this is unlikely to inhibit LNG exports as the government plans to secure new LNG capacity outside Malaysia, rather than retain domestic production for local use, the country's position as a gas exporter is also being constrained by the gradual maturing of its upstream asset base.[15] As a result, Australia is set to overtake all its competitors in the Asian gas market over the next five years, and is well positioned to become the dominant producer in the region if it can manage the growth of its LNG industry successfully.

Figure 4: Major gas suppliers to Asia



Source: BP (2014)

Australia's earliest gas reserves and production were located in the offshore Gippsland Basin in south-east Australia, which have been onstream for over 40 years, while the Cooper Basin, located

[12] BP(2014)
[13] Reuters, 26 June 2013, "The energy behind Qatar's rising power"
[14] EIA country report on Indonesia, 5 March 2014 at http://www.eia.gov/
[15] EIA country brief on Malaysia, 3 Sept 2013 at http://www.eia.gov/

across South Australia and Queensland (see Map 1), has been producing gas for 35 years.[16] However, as indicated in Table 2 and Map 1 the vast majority of the country's natural gas is now located offshore Western Australia. Table 2 details the Economic Demonstrated Resources (EDR)[17] and the Sub-Economic Demonstrated Resources (SDR)[18] in the three main basins in Western Australia (Carnarvon, Browse and Bonaparte). As can be seen the Carnarvon Basin contains almost 60% of the country's total gas resource, while the three Western Australian basins combined hold more than 90% of Australia's natural gas.

Table 2: Australia's natural gas resources

	EDR		SDR		Total Resources	
	Bcm	*PJ*	*Bcm*	*PJ*	*Bcm*	*PJ*
Carnarvon Basin	1924	74700	690	26800	2614	101500
Browse Basin	461	17900	448	17400	909	35300
Bonaparte Basin	260	10100	306	11900	567	22000
Gippsland Basin	180	7000	59	2300	240	9300
Other	95	3700	31	1200	126	4900
Total	**2920**	**113400**	**1535**	**59600**	**4455**	**173000**

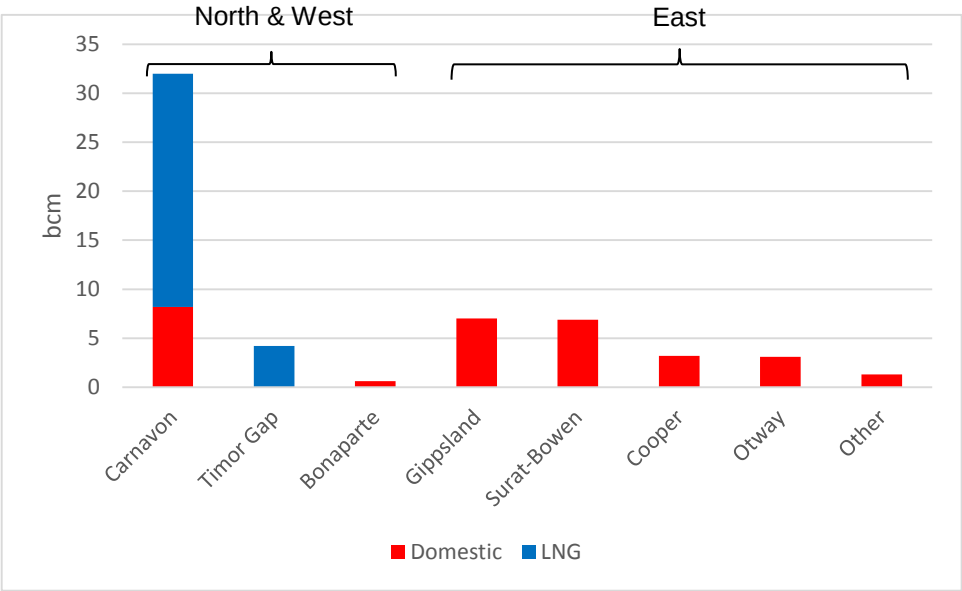
Source: BREE (2012)

The location of the reserves shown in Map 1 below underlines a number of other fundamental distinctions in the Australian gas market. The first is that it is in fact three markets, which are not currently physically linked. One pipeline system is in the west, and links the south-western and goldfields regions of Western Australia with the gas fields on the North-West Shelf. The second, much smaller, region is in the north and covers the Northern Territory, linking Darwin with onshore reserves in the Amadeus Basin and with new fields in the Bonaparte Basin. The third is in the east and covers many parts of Queensland, New South Wales, Victoria, South Australia and Tasmania, with a complex pipeline network linking the main consuming centres with the main producing basins.

The second fundamental distinction is in the location and type of reserves in each area. In the north and west the reserves are largely located in offshore, conventional gas fields, while in the east production initially came from conventional onshore fields but the focus is now gradually shifting to unconventional resources, especially CSG. A third distinction is that the larger offshore fields in the north and west have always had a primary goal of selling to the export market, with domestic sales essentially being in effect a politically enforced by-product of the field developments. In the east production has to date been entirely focussed on the domestic market. This contrast is underlined by Australia's production statistics, which clearly show the distinction between domestic and export sales in each region (Figure 5).

[16] BREE (2014) p.22
[17] Economic Demonstrated Resources are resources with the highest geological and economic certainty, and include proved and probable reserves.
[18] Sub-Economic Resources are resources for which accurate economic parameters have not yet been defined to establish profitable development. They can include possible reserves and other resources.

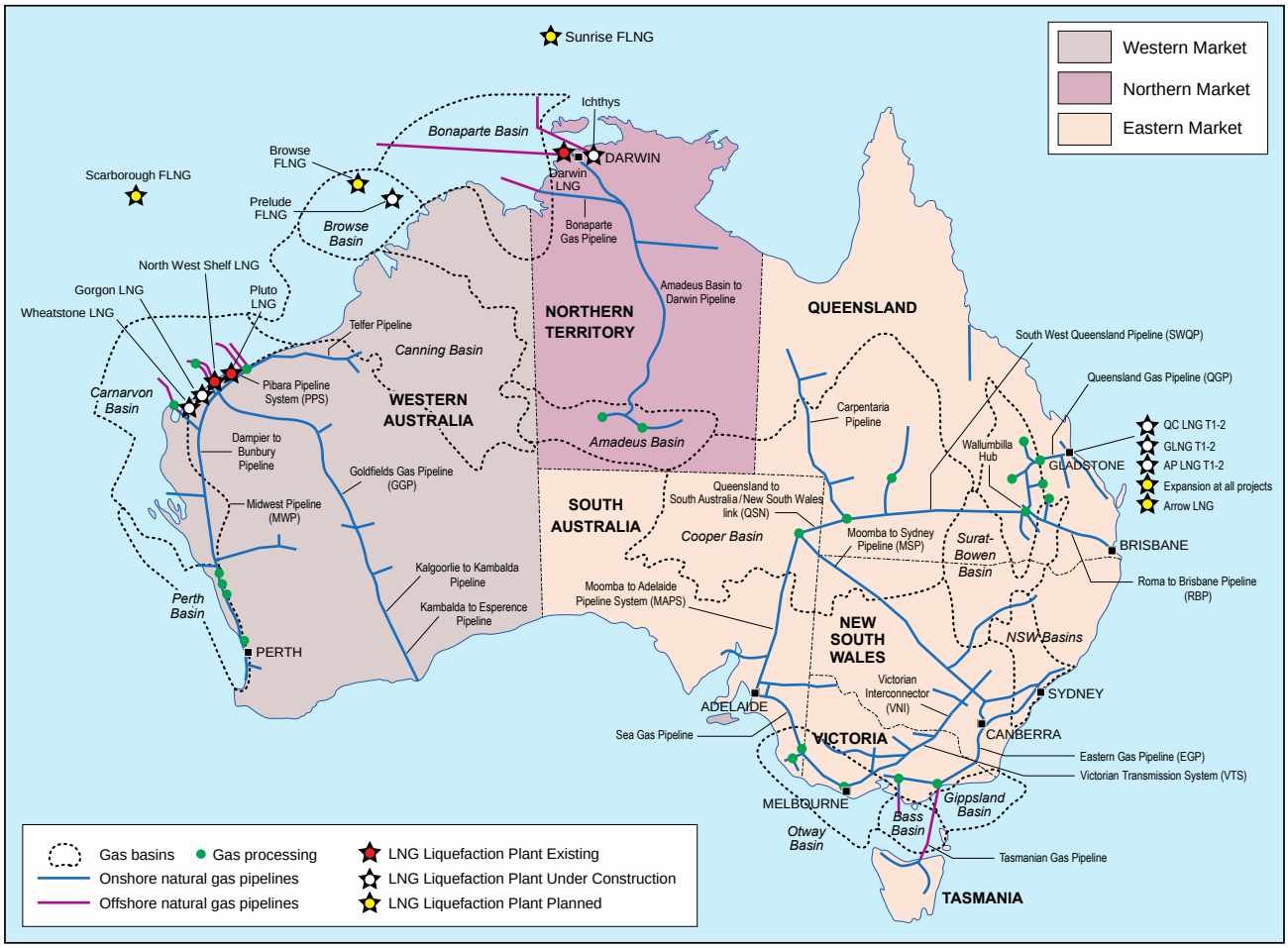
Figure 5: Australian gas production by region (2012)



Source: APPEA

Map 1 also shows some of the key pipelines, LNG export projects and the key market areas in Australia. As one considers the regional nature of the country's gas market one other important distinction needs to be made about the development of the industry, namely that the federal and regional governments have their own, sometimes conflicting, roles. For example, ownership and regulation of gas in Australia depends on where the gas resource is located, with the States owning the mineral rights to onshore gas and offshore gas inside a 3 nautical miles distance from the coast, while the Commonwealth government owns and regulates offshore gas more than 3 nautical miles from the coast. The details are discussed in Appendix 2, but in summary a number of the problems that have arisen concerning field development, gas reservation and the interaction of domestic and export markets for Australian gas concern not only the commercial issues but also the political interaction between individual States and between the States and the federal government. Later in the paper we will highlight the areas, particularly in Eastern Australia, where this division of responsibility has led to some confusion over policy creation and implementation.

Map 1: Australian domestic market, major pipelines and LNG export projects



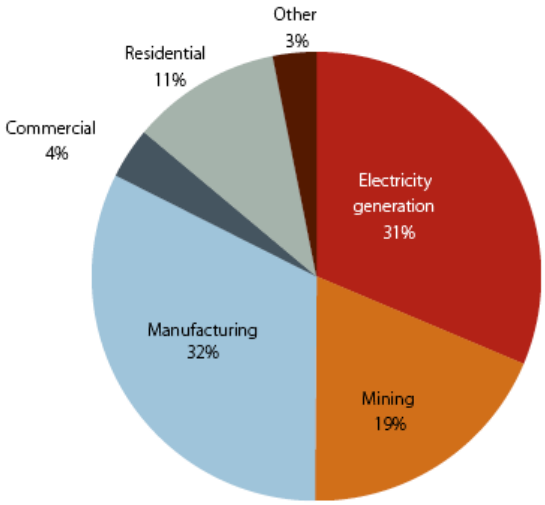
Source: Author research

2.3 Australian gas demand

From a demand perspective, Australia's annual domestic consumption of gas is relatively small in global terms, totaling 1102 PJ (28.4 Bcm) in 2012−13, which was 3.2% more than the previous year. Gas was mainly used in manufacturing (32%), electricity generation (31%), mining (19%) and residential (11%), as set out in Figure 6.[19]

[19] BREE (2013a)

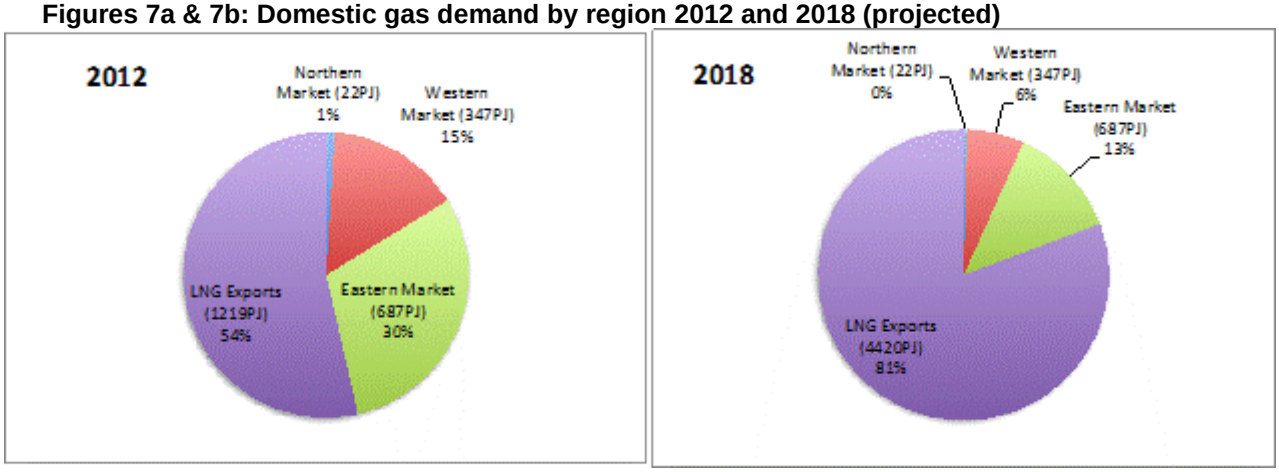
Figure 6: Gas demand by sector 2012-13



Source: BREE (2013a) p.26

Figures 7a and 7b show the split of energy consumed in each of the three domestic markets identified above as well as gas exported as LNG in 2012[20] and 2018. LNG exports, which currently only originate from Western Australia and Northern Territory, accounted for 54% of gas consumption in 2012 with the eastern market being the highest domestic consumer (30% of total production), followed by the western market (15%) and the northern market (1%). The quantity of LNG exports rose in 2013 to 22.3 mtpa (30.5 Bcma) up by 9% from 2012 and by 2018 the proportion of Australian produced gas exported for LNG is projected to rise to 81%.

Figures 7a & 7b: Domestic gas demand by region 2012 and 2018 (projected)



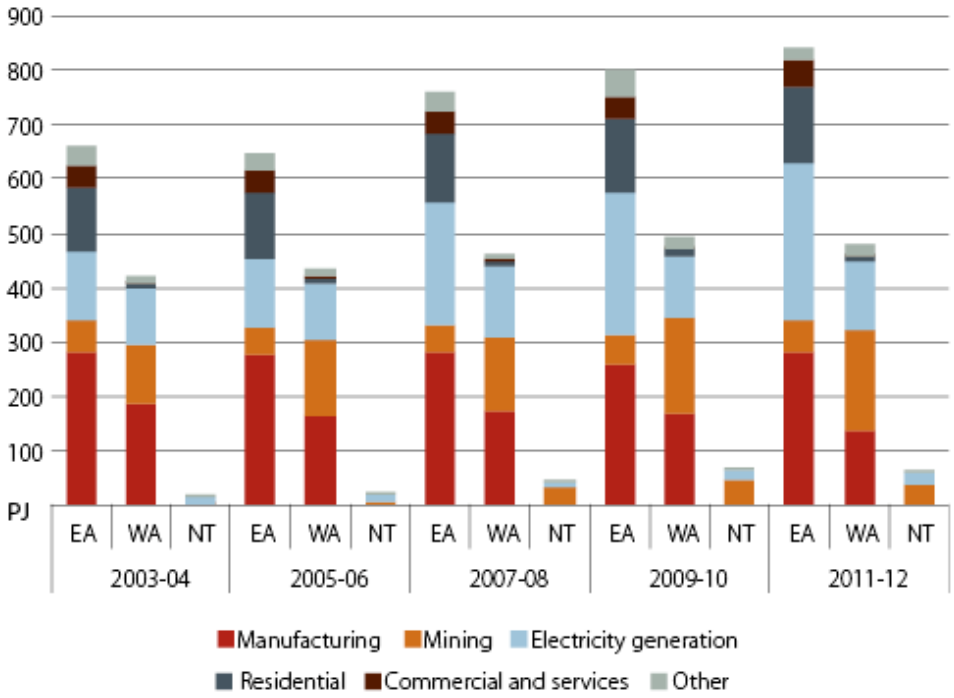
Source: BREE (2013a)

The quantity of gas consumed domestically by industry in each market is shown in Figure 8[21]. In the western market, mining is the largest consumer of gas, followed by manufacturing, electricity generation and residential. In the eastern market, consumption is dominated by manufacturing, followed by electricity generation, residential, mining and commercial. The northern market uses gas

[20] BREE (2014) p.37
[21] BREE (2013a) p.28

for mining and electricity generation. The volume of gas consumption has increased over time, but over the period 2003-2012 the proportion of gas used by each sector has remained fairly constant.

Figure 8: Gas demand by industry (2003-2012)



Source: BREE (2013a) p.28

However, the combination of increasing domestic demand and a dramatic rise in LNG exports is creating difficulties for the regional and federal authorities as they seek to find a balance between the interests of consumers in Australia and producers who wish to generate higher export revenues. The federal government's 2012 Energy white paper[22] identified the need for more infrastructure and increased investment to achieve the production and gas sales goals that it has set, but the achievement of both these targets within a relatively compressed timetable has created cost inflation and labour shortages that have led to the delays in almost all of the country's main energy projects. The northern and western regions have been hit particularly hard, but the projects in the east have also suffered from project execution issues, as will be discussed in detail in a later section.

More fundamentally, though, the expected increase in domestic sales and LNG exports has created the imminent prospect of interaction between the domestic and export markets with significantly different pricing and supply/demand dynamics. The government of Western Australia was forced to address this issue first, being the region with the earliest export sales from the North West Shelf project. Under pressure to supply the State Electricity Commission of Western Australia and local industries it introduced a gas reservation policy in 2006, insisting that 15% of any gas from an export project should be saved for domestic customers. As will be discussed later, despite the creation of this policy, gas prices in the State have still increased sharply, impacting the other exporting industries in the region and the local economy.

[22] Australian Government (2012a),

The east of Australia is beginning to face the same issue, but from a more difficult starting point. Industrial and residential consumers have been used to purchasing gas at relatively low prices from producers owning relatively low cost reserves with no alternative market. Both these determinants of price have however changed. The cost of gas in the east is rising as more unconventional reserves are brought online, and producers will soon have the option of selling into the Asian export market via three potential LNG export projects in Queensland. Furthermore, many of the long-term contracts for gas sales into the main consuming market in New South Wales are reaching their expiry dates. As well as creating a deterrent to signing new long term contracts, uncertainty over both the availability and cost of future supplies is stimulating a major debate in all the relevant eastern States, with environmental, security of supply, industrial policy, domestic political and foreign policy issues all being raised. At stake is potentially the future role of Australia as a major energy supplier into the Asia-Pacific region, with the economic and geo-political consequences that implies.

3. Australia's three existing LNG projects

Given the country's large gas resource base, its relatively low level of domestic consumption and the limited growth potential of the domestic market it has always been clear that much of Australia's gas must be exported if it is to create economic value, and given the distance to potential overseas markets it must therefore be transported by sea in the form of liquefied natural gas (LNG). To this end three projects have already been developed by consortia which include the majority of the world's major international oil companies as well as the major Australian players.

3.1 The North-West Shelf

Australia's first LNG development was the North-West Shelf (NWS) project offshore Western Australia. Operated by Woodside Petroleum on behalf of a consortium that also includes Shell, BP, Chevron, BHP, MiMi (Mitsubishi and Mitsui), the project has been in operation since 1989 and has delivered more than 3,000 cargoes to the Asia-Pacific region as well as supplying the domestic west Australian market. With gas being produced at the North Rankin, Goodwyn and Angel fields, the five trains at the LNG plant now have a full capacity of 16.3mtpa (22bcma), having cost a total of $27 billion to develop over the life of the project to date. Additional development of the North Rankin field and a number of other satellite fields was completed in 2013/14, while the development of a new area - the Greater Western Flank of the North-West Shelf – is scheduled to be completed by 2016, with 16 fields containing reserves of 3Tcf (85bcm) of gas and 100 million barrels of oil due to be tied back to the Goodwyn A platform. The addition of these new reserves will underpin the long-term future for the overall project, with production now set to continue beyond 2040.

The North-West Shelf project has established a number of precedents that continue to play a part in the debate about the future role of gas in the country. The first important marker, insisted upon by the Western Australian government and now being considered in other States, was that gas should be provided to the domestic, as well as the export, market. NWS sold its first domestic gas in 1984, five years before LNG exports began, and set an example that was finally crystallized in 2006 when the Western Australia government announced a gas reservation policy that forces 15% of all gas produced in the State to be kept back for domestic users and sold at prevailing domestic prices. As will be discussed later, this has not prevented domestic gas prices rising over the past few years, but it has certainly delayed the timing of Asian LNG and Australian domestic prices being fully linked on a netback basis.

A second major domestic impact of NWS has been on the development of the local economy, with the project sourcing approximately half of all its capital and operating expenditures in the Australian

market during the initial development phase, and increasing this figure to as high as 88% in the second half of 2012.[23] In September 1991 the University of Western Australia estimated that for every job created within the operational NWS project, 20 jobs were created outside.[24] This economic growth has allowed Western Australia to become a hub for LNG development in Australia and has also injected significant cashflow into the local economy (currently estimated at A$600 million/year through operating costs alone).[25] However, cost and wage inflation have also been driven up by the intensity of the new development work being carried out across the country's LNG industry, leading to a debate about whether more work in future will need to be carried out overseas in order to reduce cost pressures. This point is discussed in the next section.

In terms of international sales, the NWS project reflects the trend for Australian LNG as a whole, with the vast majority of its LNG being contracted to a wide range of Japanese, Chinese and Korean buyers, while any remaining cargoes are largely traded on a spot basis with buyers in a range of countries. However, the growing influence of the Chinese market and companies is evident through the involvement of Chinese state company CNOOC at NWS, where the company purchased a 5.3% stake in the liquids production from the upstream projects in May 2003 (but not in the liquefaction plant) and also has a 25% stake in the China LNG JV which supplies LNG to the Guangdong terminal in SE China under a 25 year contract. Chinese companies have since become even more heavily involved in a variety of other Australian LNG projects, with investments in current and future developments discussed in the next section, reflecting the rapid expansion of the Chinese gas market, the desire of Chinese companies to invest in the upstream equity of projects that will supply their gas and the political support of the Australian government to develop closer commercial links between China and Australia.

[23] Government of Western Australia (2013a)
[24] The University of Western Australia (1991)
[25] Woodside Petroleum, North West Shelf Project Brochure, www.woodside.com.au/northwestshelf, accessed 12 Dec 2013

The North West Shelf onshore facilities in Western Australia

3.2 Darwin LNG

Australia's second LNG scheme is the much smaller Darwin LNG project, which is located in the Northern Territory and produced its first LNG in 2006. With a capacity of 3.5mtpa the LNG plant receives its gas from the 100bcm Bayu Undan field located in the Joint Development Area in the Timor Sea[26] and then sells it under 17 year contracts to Tokyo Gas and Tokyo Electric in Japan. Planning permission has been received to expand the liquefaction plant to a capacity of 10mtpa if new fields in the Timor Sea or Bonaparte Basin are developed, but although it would appear that a number of companies might be interested in sending gas either from these waters to Darwin, no specific plans have yet been announced.

3.3 The Pluto Project

The best illustration of the Australian LNG industry's current issues is provided by its third development - Woodside's Pluto project, which is located not far from the NWS development in the Carnarvon Basin. In phase 1 of the project, which produced its first LNG in April 2012, an onshore liquefaction facility with one 4.3 mtpa train receives gas via a 180km pipeline from the Pluto and Xena offshore gas fields. The project has been underpinned by 15-year sales contracts with Tokyo Gas and Kansai Electric in Japan, both of whom are purchasing 2 mtpa.

[26] Joint Development Area with Timor Leste, with 90% of gas or revenues going to Timor Leste.

However, despite the ultimate success in bringing the Pluto development online, the project provides an example of the delays and cost overruns that are facing the Australian LNG industry as it seeks to develop numerous projects at the same time. The history of the Pluto project is shown in Table 3, and underlines the risks that currently face investors in the Australian gas sector. Having originally been given FID sanction in July 2007 with an expected date for first LNG in February 2011 and with an estimated development cost of US$11.2 billion, the first increase in the cost estimate came in November 2009 when a 6-10% increase was blamed on "lower than budgeted productivity in both onshore and offshore construction." [27] This was followed in December 2009 by the first of two strikes which saw half of the project workforce walk out over pay and conditions, with the second strike coming in June 2010, after which a 6 month delay in the project schedule was announced as well as a further 7% increase in the cost estimate. In June 2011 a further 6% was added to the overall project cost, taking it to US$14.9 billion, with another 6 month delay also announced, taking the expected first LNG date back to March 2012. However, even this date proved too optimistic and, following some technical changes to the plant's flare stack, the project finally came online in April 2012, with the first LNG cargo exported in May 2012. Overall, then, the project finally started up 15 months late (a 35% schedule overrun compared to the original plan) and at a cost US$3.7 billion, (33%) above the original estimate. That said, once it did complete commissioning, the project ramped up production very quickly and is operating over nameplate capacity.

The key drivers for this poor project management performance appear, to the authors, to be increasing labour costs caused by a tight labour market in the oil and gas sector, a strengthening local currency, some project management and design inefficiencies, general cost inflation for materials and an increasing focus from regulators and the local population on the environmental impact of projects. As will be discussed below, given that these issues impacted this project rather severely, it is not surprising that some of the same factors are causing delays and cost overruns amongst the seven new projects that are currently being developed in Australia simultaneously. Indeed the coincidence of events in Australia that has led to the escalation in plant costs and has also contributed to a series of project delays has been noted in a recent OIES working paper by Brian Songhurst, who observed that "the very high cost of the current Australian projects is unique to that location and driven by a strengthening Australian dollar, the very high construction costs and the remote locations far from any infrastructure."[28] Some of these factors are not unique to Australia, with cost overruns and delays also being experienced in projects in the Atlantic Basin and Middle East.

[27] LNG Intelligence, 23 Nov 2009, "Woodside flags cost increase at Pluto LNG project"
[28] Songhurst (2014)

Table 3: Delays and cost overruns at the Pluto LNG project

Date	Event	Comment
Jul-07	FID	Initial cost estimate of $11.2bn with an estimated completion date of Feb 2011.
Nov-09	Cost estimate increased	Total capex estimate increased by 6-10%.
Dec-09	Worker strike	Half of Pluto workers strike over pay and conditions.
Jun-10	2nd worker strike	Strike by crane and forklift workers. Woodside warns of project delays and cost overruns.
Nov-10	Project delay and cost increase	Delay to August 2011 and 7% increase in cost estimate to $14bn.
Jun-11	Project delay and cost increase	Delay to March 2012, cost estimate raised by $900mm (6% increase)
Mar-12	Project delay	Start-up delayed by 1 month
Apr-12	Project start-up	First LNG produced
May-12	First LNG delivered	Exports to Japan begin

Source: Data collated by author from various journals

4. The 2010s growth spurt of Australian LNG

Abundant gas resources offshore north west Australia and technology advances supporting the development of CSG exploration and production on the east coast, combined with the expectation of historically high Asian LNG prices as a consequence of $100+/bbl oil, have all led to a plethora of final investment decisions[29] (FIDs) for Australian LNG projects being taken between 2009 and 2012. Currently there is massive LNG plant construction activity underway at seven projects under development, comprising 14 LNG liquefaction trains, which will provide an additional 62 mtpa of LNG capacity (equivalent to 54% of the global liquefaction capacity that is under construction as at the end of 2013), with more than $200 billion of capital expenditure committed to this expansion.[30] The details of the size, scope and timing of these projects is detailed in Table 4, along with the participants in each project.

Of the 62 mtpa of LNG projects under construction, just over half of the capacity (33 mtpa) is located on the North-West Shelf and is being developed in a series of land based projects, under a traditional structure with long-term offtakers and dedicated gas reserves. These projects have been developed by strong LNG-experienced companies and in some projects the shareholders have contracted for part of the LNG volume to be traded under their own portfolio. In addition, 3.6 mtpa (6% of the LNG projects currently under construction), will be produced by the Shell sponsored Prelude project using floating liquefaction (FLNG). This very large floating facility is 488 metres long and 74 metres wide, the approximate size of more than 4 soccer pitches. Gas supply for this facility will come from the

[29] Final Investment Date (FID date) is the date on which the project sponsors decide to make a binding financial decision to proceed with the project. Usually the key agreements related to the project are signed on this date (e.g. plant construction, gas purchase, LNG sales and financing agreements).
[30] Source: Australia LNG Insight October 2013 "Australian LNG Busting the Budget" (Insight)

Prelude gas field, close to where the floating facility will be located, and this massive offshore facility will produce at least 1.7 mtpa of natural gas liquids[31].

Schematic of Prelude FLNG vessel

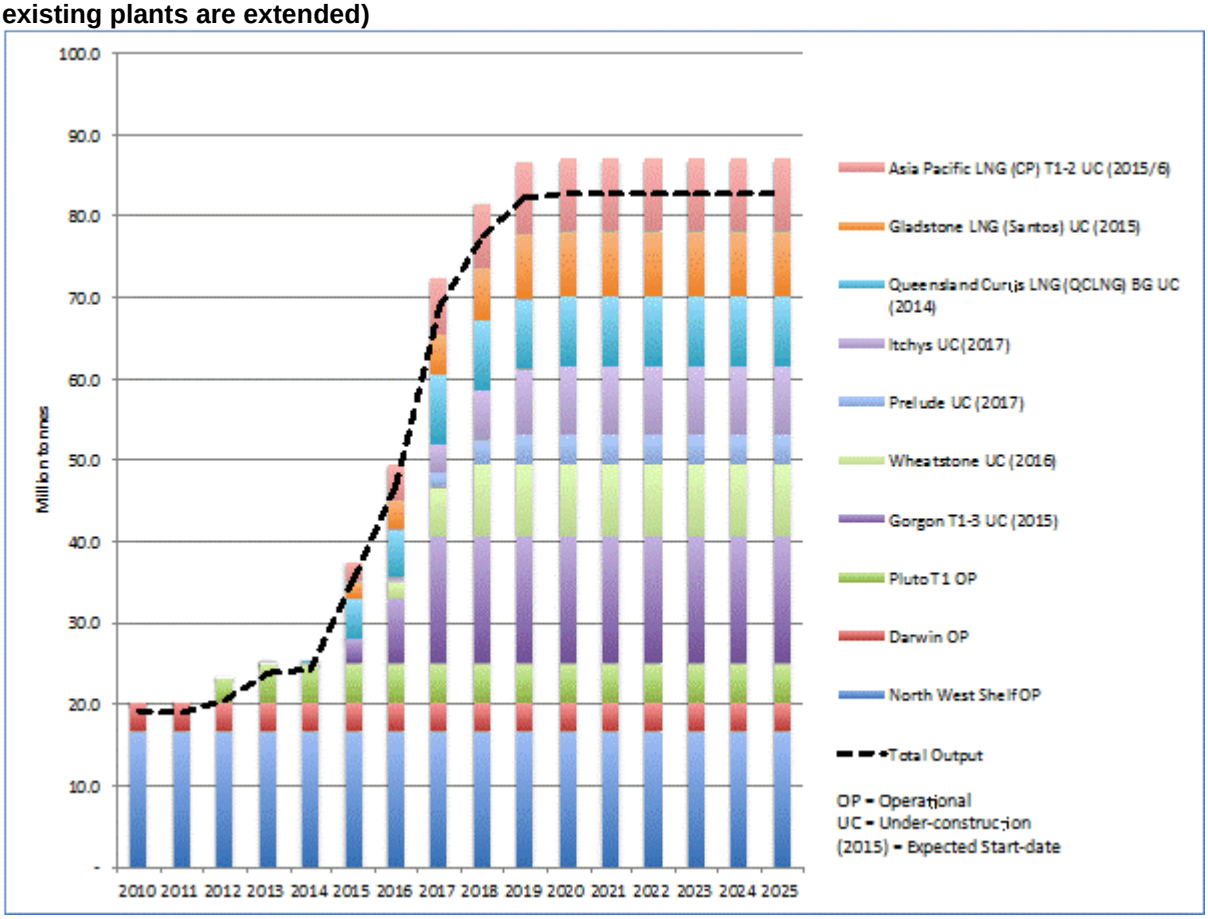
Source: Shell

On the east coast of Australia, three LNG projects are being developed which, when operating at plateau, will add an additional 25 mtpa of LNG capacity. These projects are all located close to each other on Gladstone Island in Northern Queensland and are based on the development of Coal Seam Gas reserves in Queensland.

By 2020, even if no additional projects reach FID, the production capacity of Australian LNG will be 87 mtpa. Assuming a plant utilization of 95% (based on the average Australian production 2000-2010), this should result in 83 mtpa of LNG production.

[31] http://www.shell.com/global/aboutshell/major-projects-2/prelude-flng/overview.html

Figure 9: Estimate of Australian LNG export capacity (Note: Assuming that contracts for existing plants are extended)



Source: David Ledesma research and analysis

Table 4: LNG projects under construction in Australia (January 2014)

Project	FID	Est. Start date	Shareholders (Operator underlined)	Gas Supply Source	Capacity mtpa	Long-term LNG Sales (Equity & Sales volumes)	Type/Location CV=Conventional Gas CSG= Coal Seam Gas
Gorgon Train 1	Sep-09	End 2015/early 2016	Chevron:47.33%; Shell: 25%; ExxonMobil: 25%;Osaka Gas:1.25%; Tokyo Gas: 1.00%; Chubu Electric: 0.417%	Greater Gorgon and Janszgas fields	5.2	Shell 1.4; BP 0.5; Tokyo Gas 1.25; Chubu Electric 1.5; Osaka Gas 1.6; Caltex 0.25*; Petronet 1.5; Petrochina 4.25; Uncommitted EM: 0.15; Uncommiited Chevron: 2.6 *Balance 0.25 to GS-Caltex from Chevron portolio	CV Barrow Island Western Australia
Gorgon Train 2	Sep-09	end 2016			5.2		
Gorgon Train 3	Sep-09	2017			5.2		
Wheatstone Train 1	Sep-11	Late 2016	Chevron: 64.14%; Kufpec: 13.4%; Apache: 13%; PEW*: 8%; Kyushu Electric: 1.46% *TEPCO will hold a 0.1% interest in PEW, with the remaining equity held by Pan Pacific Energy, an investment vehicle held in turn by OGMEC (42.08%), Mitsubishi (39.7%), NYK Line (10.2%) and TEPCO (8.02%).	Wheatstone, Lago, Julimer and Brunello fields supported by Clio and Acme fields (for potential expansion). Phase 1 includes gas supply to a domestic gas plant at the Ashburton North Strategic Industrial area about 12 kilometers west of Onslow on Western Australia's Pilbara	4.45	Tepco 4.2; Kyushu Electric 0.8; Tohoku Electric 0.9; Chubu 1.0, Shell 0.6 Uncommitted 1.5	CV Ashburton North Western Australia
Wheatstone Train 2	Sep-11	2017			4.45		
Prelude	May-11	Early 2017	Shell: 67.5%; Inpex: 17.5%; Kogas: 10%; CPC 5%	Prelude gas field, adjacent to Ichthys 450km offshore Kimberley	3.6	Kogas 3.6 (but the volume could be supplied from Shell portfolio)	
Ichthys Train 1	Jan-12	2017	Inpex: 63.445%; Total: 30%; CPC: 2.625%; Tokyo Gas: 1.575%; Osaka Gas: 1.2%; Chubu: 0.735%; Toho Gas: 0.42%	Ichthys field, 850 km offshore Darwin	4.2	Tepco 1.05; TG 1.05; Kansai Electric 0.8; Osaka Gas 0.8; Kyushu Electric 0.3; CPC 1.75; Toho Gas 0.3; Chubu Electric 0.5; Inpex 1.1; Total 0.7-0.9 to Kogas as a swap for US LNG	CV Blaydin Point Northern Territory
Ichthys Train 2	Jan-12	2017/8			4.2		
QCLNG Train 1	Oct-10	2014	BG: 50%; CNOOC: 50%	Surat and Bowen Basins, with operational cooperation with APLNG	4.25	BG 4.0; CNOOC 3.6*; Tokyo Gas 0.9**; Chubu Electric 0.4 *Additional 5 mtpa from BG portfolio (some may come come QCLNG) **Additional 0.3 from BG portfolio	CSG Curtis Island Queensland
QCLNG Train 2	Oct-10	2015	BG: 97.5%; Tokyo Gas: 2.5%		4.25		
GLNG Train 1	Jan-11	2015	Santos: 30%; Petronas: 27.5%; Total: 27.5%; Kogas: 15%	Surat and Bowen Basins with additional gas from the Cooper Basin	3.9	Petronas 3.5; Kogas 3.5	CSG Curtis Island Queensland
GLNG Train 2	Jan-11	2015			3.9		
Asia Pacific LNG T1	Jul-11	2015	ConocoPhillips: 37.5%; Origin: 37.5%; Sinopec: 25%	Surat and Bowen Basins with additional gas supply potentially from Arrow and other third party blocks. Operated by Origin Energy	4.5	Sinopec 7.6; Kansai Electric 1.0	CSG Curtis Island Queensland
Asia Pacific LNG T2	Jul-12	2016			4.5		
					61.8		

Source: David Ledesma, research, analysis and views

4.1 Challenges facing project construction

Project developers have faced considerable challenges in bringing each project to FID and subsequently constructing the facilities on time and on budget. Table 5 below provides some details of the cost overruns that have been experienced at the seven projects currently under development, indicating an average increase from the initial cost estimate at FID of approximately 25% or a total of $40 billion for the projects in total. Furthermore, the delays in start-up, although apparently less dramatic, have also had a significant impact on the project economics and have even put some of the gas sales contracts at risk. For example, delays to the Gorgon start-up could affect the gas plant and domestic contracts with Verve Energy and Synergy that were due to start in 2015. This data has been taken from public statements, and author's estimates, and in some cases companies do not state the exact capex cost of the projects and specifically the liquefaction portion. It is therefore difficult to compare projects, especially when some figures include liquids benefits (which could give large revenues). This table however, gives an indication of different costs and changes in capex costs and start-up dates since FID.

Table 5: Australian LNG projects under construction – cost escalation and time delays

Project	FID	Est. Start date at FID (First Cargo)	Est. Start date at June 2014 (First Cargo)	Capacity mtpa	Budget At FID US$ bn.	Budget at June 2014 US$ bn.	Percentage increase of budget	US$/mt capacity $000
Gorgon	Sep-09	2014	End 2015/7	15.6	37.0	54.0	46%	3,460
Wheatstone	Sep-11	2016	2017/8	9.0	26.4	29.7	13%	3,300
Prelude	May-11	Late 2016/ early 2017	2017	3.6	12.0	12.0	-	3,330
Ichthys	Jan-12	2017	2018	8.4	34.0	44.0	29%	5,240
QCLNG	Oct-10	2014	2015*	8.6	15.0	20.4	36%	2,370
GLNG	Jan-11	2015	2016**	8.0	16.0	18.5	16%	2,310
Asia Pacific LNG	Jul-11	2015	2016	9.0	20.0	22.5	13%	2,500

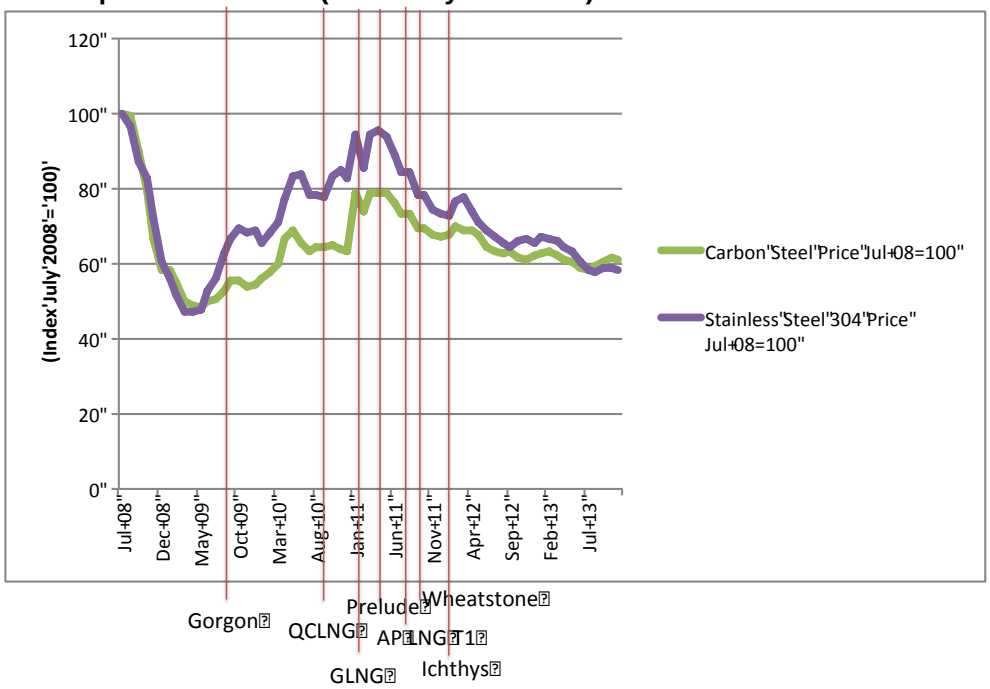
* QCLNG targeting end 2014
** GLNG targeting end 2015

Source: David Ledesma research and company websites

Rising material costs

Rising raw material costs have been one key catalyst that has driven up the price tag of the earlier projects. Figure 10 shows how the cost of materials, in particular steel, has increased following the dates on which the Engineering Procurement Contractor (EPC) bids were prepared for FID. These additional costs will be borne by the project investors themselves, unless they passed the risk of materials cost escalation to the EPC as part of the construction contract. However, at the time that the EPC contracts were awarded for the Australian contracts, contractors were reluctant to take such risks following their experiences in Qatar when fixed priced contracts resulted in the EPC being liable for higher raw material and labour costs which could not then be passed on to the equity participants in the projects. In Australia's case, projects that awarded EPC when the price of steel was at its peak, may enjoy some savings, which could help absorb some of the cost overruns.

Figure 10: Steel prices 2008-2013 (Index July 2008=100)



Source: Reference Carbon Steel and Stainless Steel 304 Data Source (Refer to table: World Composite Steel Price and Index [Price columns]) http://www.worldsteelprices.com/index.htm

An additional factor that has also contributed to rising material costs is that, as noted by Songhurst, the more recent plants in Australia have asked suppliers, in common with many other projects around the world, to modularize their equipment in order to minimize construction work at the site due to high labour costs and personnel restrictions (see further discussion below). Unfortunately, while major suppliers such as GE provide world class equipment on an individual basis, modularization is not their area of expertise, and this has led to higher costs and extended schedules for work that might have been done more cheaply and quickly by specialist fabricators. As a result, the unintended consequence of trying to save on costs in one area (labour) may have been to increase costs and slowed progress in another.[32]

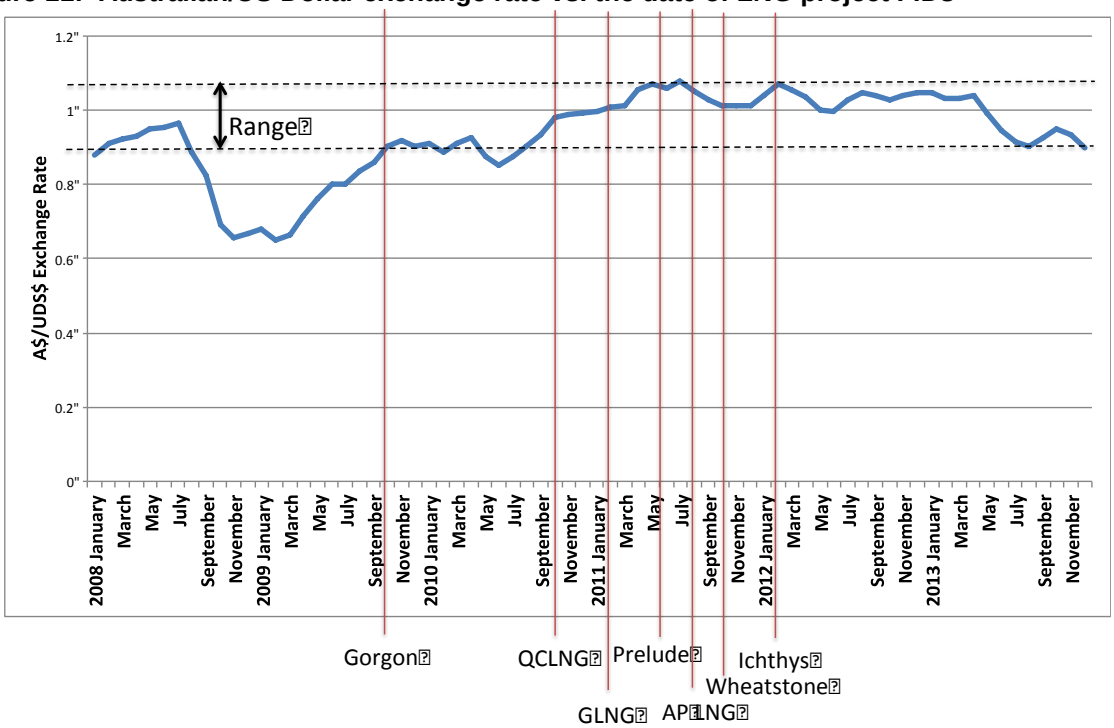
Stronger Australian dollar

The impact of the strengthening Australian Dollar has also been an important contributor to cost inflation, with Chevron, for example, suggesting that it has caused one third of the rise in costs at the Gorgon project.[33] As set out in Figure 11, the Australian Dollar strengthened by over 20% (relative to the US Dollar) between September 2009, when the FID for Gorgon was taken, and end 2012, before falling back to its earlier levels. As direct labour costs represent 20-27% of an LNG plant's capex cost[34] and shareholder and project management costs increase this further to 40-50%, and these costs have to be paid in Australian Dollars, while source funding is usually in US Dollars, the strengthening Australian Dollar has a direct impact on project costs. The main impact has been felt by those projects that took earlier FID, although the exact outcome depends on the exchange rate assumptions used by the shareholders at the time that their various cost estimates were made. The

[32] Songhurst (2014)
[33] Songhurst (2014) p.20
[34] http://www.kbr.com/newsroom/publications/technical-papers/lng-liquefaction-not-all-plants-are-created-equal.pdf Page PS4-1.8

weakening of the Australian Dollar during 2013 will have given some relief, but only for those costs that were incurred at that time. This may explain why additional large cost overruns have not been announced over the past twelve months[35].

Figure 11: Australian/US Dollar exchange rate vs. the date of LNG project FIDs



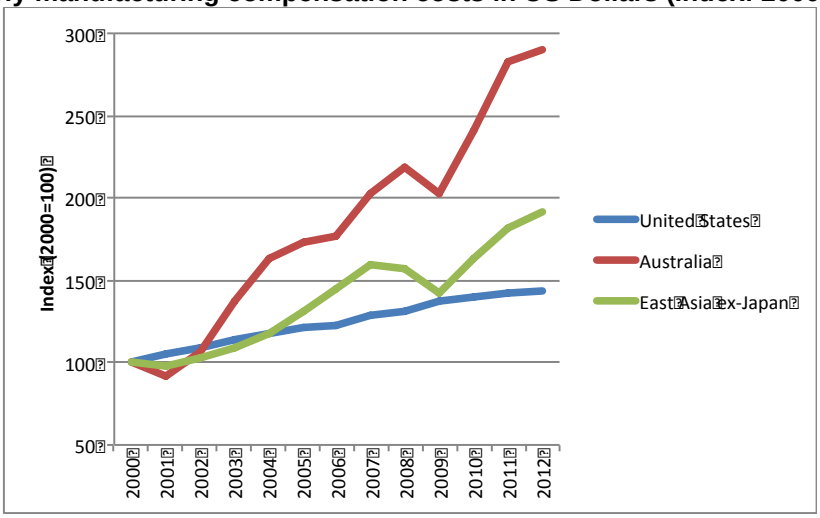
Source: David Ledesma analysis (exchange rate date from www.oanda.com)

Labour costs and the power of the unions

As previously indicated, the cost of labour has also played a major role in the cost overruns at Australian LNG projects. Figure 12 compares compensation (wage) costs, in US Dollars, for Australia with costs in the United States and East Asian countries (excluding Japan). It is accepted that the Australian data does not specifically cover the LNG sector, but it can be seen that between 2009 and 2012 the cost of labour in Australia increased by over 40%, rising at a rate considerably higher than the United States and East Asian countries. In specialist trades it increased by far more. It should be noted that Figure 12 shows compensation costs in US Dollars. Because there has been a 20% strengthening in the Australian Dollar, the increase in Australian costs would be lower than the non-currency corrected data.

[35] "RBAs Tanna Says Aussie's Drop to Boost Commodity Export Returns", www.B**loomberg,** 2/8/13

Figure 12: Hourly manufacturing compensation costs in US Dollars (Index: 2000=100)



Source: US Department of Labour, Bureau of Labour Statistics 2012; Table 1.2 (http://www.bls.gov/ILC/#compensation) Hourly compensation costs in manufacturing, U.S. dollars, 1996-2012. David Ledesma analysis.

A number of examples of high costs, and in particular high wages, in Australia can provide further evidence to back up the conclusions from Figure 12. Australian oil and gas workers earn an average of US$163,600 per annum, 35% more than similar employees in the US and double the global average, according to a survey by a recruiting company quoted in the Wall Street Journal.[36] Meanwhile according to Shell a welder can earn as much as US$250,000 per annum.[37] And in terms of the overall cost of major infrastructure projects in Australia, when compared to the US, airports are 90% more expensive to deliver, hospitals 62%, shopping centres 43% and schools 26%.[38]

These high costs have resulted from a tight labour market in Australia and also from the significant power that trade unions wield in the country. The development of seven new LNG plants at the same time naturally led to a shortage of skilled labour in a country with a relatively small population, but this situation was exacerbated by Australia's strict rules on using foreign workers. In particular the rules on applying for a temporary work visa (known as the Temporary Work (Skilled) (sub-class 457) visa, or the 457 visa for short)[39] have meant that companies need to first advertise any position within the domestic market before they can appoint a foreigner to a position. Furthermore, the Labour government that was in power until September 2013 imposed restrictions on the number of visas which any one company could apply for on behalf of foreign workers, and also forced companies to provide exact estimates of how many workers they would have employed under 457 visas in any quarter, with fines then imposed for exceeding these estimates.[40] All these factors combined to provide a huge advantage for domestic employees in skilled and even semi-skilled positions, and allowed the unions to argue not just about the use of foreign workers in long-term employment but also about short-term employment issues, for example the use of foreign workers on ships used for short-term contracts. The new Liberal government has now started to unwind some of the foreign

[36] http://online.wsj.com/article/BT-CO-20130207-718721.html, accessed on 4 June 2014
[37] http://www.bloomberg.com/news/2013-04-25/highest-paid-workers-driving-shell-gas-terminal-offshore.html
[38] http://www.theaustralian.com.au/national-affairs/local-project-costs-40pc-above-the-us/story-fn59niix-1226386836012#mm-premium
[39] http://www.immi.gov.au/Visas/Pages/457.aspx
[40] http://www.theage.com.au/comment/the-age-editorial/changes-to-visa-caps-could-hurt-all-workers-20140312-34moy.html

worker restrictions, but the major impact has already been felt by many of the projects that are now nearing completion.[41]

Further power was given to the Australian unions through additional legislation introduced by the previous Labour government in power when all the current projects were being negotiated, under which companies were forced to negotiate "greenfield agreements" with unions before any new project could start.[42] Essentially brand new employment terms would have to be agreed on each project with each union representing the wide cross-section of employees, with no restrictions on time limits for reaching a deal. As a result the unions were in a very powerful position if any company did not meet its terms, having the ability to delay projects indefinitely at a time when project sponsors were fighting to be first into the market with their gas. The effect of this was that unions were able to demand very high wages for even more unskilled roles such as laundry worker or driver.

Not surprisingly the unions themselves have been unrelenting in their drive to secure the best deals for their members. As the Western Australia branch secretary of the Maritime Union of Australia stated "we make no apology for trying to get a good deal for our members, who are the ones who spend weeks at a time working away from home in very tough conditions."[43] However, project operators such as Chevron have now started to respond with appeals to the new Australian coalition government, led by Tony Abbott of the Liberal Party, to change the Fair Work Act and in particular the "right-of-entry" provisions for unions that are a particularly disruptive element of the legislation.[44] This right allows union representatives to enter a workplace under various circumstances such as a suspected breach of agreement or a suspected health hazard, or even just to talk to an employee,[45] but can be used to interrupt work as a tactical ploy when negotiations on pay are ongoing. Chevron has claimed that official visits could happen as often as four times a week, causing delays and overruns as staff were prevented from progressing their work. The new Liberal government has already passed legislation in the lower house of parliament to reduce the impact of the unions, with ratification in the upper house (Senate) expected during the summer of 2014,[46] but another alternative could see a greater number of floating LNG schemes considered. These offshore projects require fewer domestic construction workers and therefore the need for union negotiation is at least somewhat reduced, although a clear negative consequence for the State governments involved is that tax revenues could fall as, depending on the exact location of the project, they could go straight to the federal government. Furthermore inward investment in the States concerned would also be lower, as FLNG ships will be constructed outside Australia.

Higher oil prices and associated liquids have provided some relief

However, these higher project costs have been mitigated by two factors. The first is the rise in oil prices (and its direct impact on the LNG price through the contract pricing formulae). Over the period 2009 to 2013 the price of crude oil almost doubled, with the average price for Brent Crude in 2009 being $62/bbl[47] while in 2013 it had risen to $107/bbl. Assuming an LNG sales price formula slope of

[41] Ibid.
[42] Reuters, 14 April 2014, "High cost Australia may miss $180bn LNG expansion wave"
[43] Ibid.
[44] The Australian, 8 April 20014, "Chevron boss Roy Krzywosinski slams union influence"
[45] Australian Government, Fair Work Ombudsman, at http://www.fairwork.gov.au/employment/unions/pages/union-visits-and-meetings
[46] Reuters, 14 April 2014, "High cost Australia may miss $180bn LNG expansion wave"
[47] BP (2014)

15% oil, this equates to an increase in the gas sales price equivalent to $6.75/MMBtu,[48] showing the positive impact of liquids production on the economics of an LNG project.

Secondly, the companies have increased the size of their projects to achieve higher returns, with one example being the Gorgon project which increased its nameplate capacity from 15 to 15.6 mtpa. In addition, the LNG projects on the North-West Shelf, unlike the Queensland CSG projects, have varying amounts of natural gas liquids (NGLs) associated with the gas production, which helps to increase revenues and boost economic returns. For example at its peak the Ichthys LNG project is expected to produce 1 million mt/year of LPG and around 100,000b/d of condensate[49]. This additional revenue stream has also benefitted from higher oil prices. These important "liquids credits", which have also underpinned the economics of the Qatari LNG projects and unconventional gas producers in the United States, have allowed the sponsors of the Australian LNG projects that are under construction to state that their projects remain viable, even at the higher costs that the projects have incurred.[50] New LNG projects are more likely to be developed if they have high liquids content.

4.2 Projects under construction

The four projects under construction in the Western Australian Market, as at the beginning of 2014, all use gas from offshore Western Australian waters although the Ichthys project plant is located onshore at Darwin, in the Northern Territories. Below we provide some details of the projects and how they have individually been affected by cost overruns, delays and development challenges:

Gorgon LNG (Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas), FID: September 2009

The Gorgon gas field is estimated to contain 1130bcm (40Tcf) of gas, and is being commercialized through a land-based LNG facility located on Barrow Island on the North-West Shelf. This gas reservoir has a high CO_2 concentration, and as part of the project the CO_2 is removed and injected into subsurface reservoirs. This has added to the capital cost of the project. Also, Barrow Island is a nature reserve, and all equipment used in the plant has to be cleaned before and after shipment to the island to avoid the introduction of non-indigenous species and diseases. This has also added to the capital cost. At FID in September 2009, the overall project cost was estimated at US$37billion for a 15 mtpa plant (equivalent to US$2,470/MT), but by the end of 2013 this had risen to US$54billion, although Chevron had by then slightly increased the nameplate capacity to 15.6 mtpa in order to partly compensate for the higher cost (equivalent to US$3,460/mt). This increase was caused both by higher material and labour costs but most significantly by exchange rate effects, which were greater for Gorgon than many of the other projects as the Australian Dollar strengthening by approximately 15% between its FID date and 2011/mid 2012 when the majority of the capital expenditure commitments took place. In addition, delays caused in the main by labour shortages have meant that, from an initial estimated start date of 2014, Train 1 has now been pushed back to a start date in late 2015, with the full 3-train capacity being reached in 2017.

[48] Sales of LNG into Asia are usually made on the basis of a formula: Price (LNG) = Price oil (normally JCC) x Factor plus a constant of 0.6 – 0.9/MMBtu for ex-ship sales and zero for FOB sales. During the period 1990-2002 the factor was 0.1485 (i.e. the price per Btu of LNG increased at ~ 86% of the oil price). From 2003 onwards sellers, driven by the Qataris, have sought to increase the 0.1485 factor towards 0.165 (oil parity). The assumed factor of 0.15 reflects the level achieved by several Australian LNG projects that are currently under construction.

[49] Source: www.platts.com "Inpex Ichthys LNG project could be $10 bil over budget" 1/8/13

[50] Ibid: Insight

The Gorgon LNG Project

Prelude (Shell, Inpex, Kogas, CPC), FID: May 2011

The Prelude gas field, 450 km offshore Kimberley, is estimated to contain 115bcm (4tcf) of gas. Shell, as the primary developer, had considered an onshore liquefaction and export development, but high domestic construction costs, together with the remoteness of the gas resource, drove the company to opt for FLNG. In May 2011, Shell took FID on the Prelude FLNG facility and when completed it will have the capacity to produce 3.6 mtpa of LNG plus 1.3 mtpa of condensate and 0.4 mtpa of LPG, equivalent to a 5.3 mtpa LNG production facility. The strategic logic of Prelude is not only to position the LNG production facility offshore in order to save the cost of moving the gas to an onshore facility, but also to allow the facility to be constructed in the Samsung shipyard in South Korea away from the potential high cost and environmentally challenging land-based locations in Australia. Importantly also Prelude, once operational in 2017, will position Shell as a large scale FLNG provider, under its "build one, build many" strategy. Prelude is being developed using Shell's DMR liquefaction process with Technip, and although the company has not specifically disclosed the capital cost of the project, public statements have indicated a total of US$12 billion. At a capacity of 3.6 mtpa this equates to US$3,300/MT. If however the facility's capacity is increased to include the liquids (i.e. 5.3 mtpa), this reduces the unit cost to US$2,260/MT.

Wheatstone (Chevron, Apache, Kufpec, PEW, Kyushu Electric), FID: September 2011

Gas for the Wheatstone project is located close to Gorgon in NW Australia, with the gas being sourced from a number of offshore fields owned by the project sponsors (Wheatstone, Iago, Julimer and Brunello) with some additional gas supply from the Clio and Acme fields to meet potential expansion. Located onshore at Ashburton, the two train 8.9mtpa Wheatstone LNG facility took FID in September 2011, and like Gorgon, has experienced cost overruns, with the initial capex estimate of US$26.4 billion increasing to US$ 29.7 billion, a rise of 13%. This project has been affected as much as Gorgon by the A$/US$ exchange rate effect, due to its later FID, although the strengthening Australian Dollar will have had some effect as contracts would have been negotiated while the currency was still appreciating. Furthermore, the project has experienced some delays, although the projects sponsors still remain hopeful that it will deliver its first cargo from train 1 in 2016, with train 2 following in 2017, although the authors believe that it is likely that train one may slip to 2017. Phase 1 of the project also includes gas supply to a domestic gas plant at the Ashburton North Strategic Industrial area about 12 kilometers west of Onslow on Western Australia's Pilbara region.

Ichthys (Inpex, Total, CPC, Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas), FID: January 2012

The two train Ichthys LNG project, Japanese driven, is located onshore at Blaydin Point, near Darwin in the Northern Territory. Gas is piped 850km from the Ichthys offshore facilities through the Ichthys Gas Export Pipeline to Darwin. The Ichthys field is located closer to Browse in WA than Darwin in NT, but the partners selected to construct the project onshore at Darwin due to their preference for the regulation in Northern Territory, in particular the lack of DMO. The project took FID in January 2012, with the decision driven in part by Japan's wish to secure additional LNG supply security following the March 2011 Fukishima earthquake. With the exception of a small volume being sold to Total, as an equity holder in the project, all the LNG will be supplied to Japan. It is expected that this project should be delivered on time and broadly on budget, as the Australian Dollar has weakened against the US Dollar since FID was taken. First cargo is expected from Train 1 in 2017 with the second train following in 2018, but it is likely that Train 1 may slip into the next year.

5. The varying importance of the domestic gas markets in Australia

5.1 Introduction

With cost and project delays being the major issue for LNG export projects, a wider issue facing the domestic market has been making sufficient gas available to meet growing energy demand across the country. However, the nature of the challenge is specific to each regional domestic market. In the west the export market has been the priority, but has also been the enabler for development of the domestic market as the State government has insisted on some domestic gas reservation. In reality it has actually been rather flexible in the face of project sponsors refusing to go ahead if the domestic burden was too onerous. In the north, with little domestic gas demand, there has been very little focus on the domestic market and export projects have been allowed to proceed without any concern for local consumption. In the east, however, the domestic market has historically been the main focus, and indeed catalyzed the development of the CSG gas supply that has now in turn become the foundation for export sales. However, consumers are now becoming increasingly worried by the impact of the new LNG export projects both on domestic prices and the availability of gas for the domestic market.

Before we turn to Eastern Australia, though, it is relevant to consider how the smaller markets in the west and the north of the country have developed and reacted to the advent of LNG exports. The majority of the gas in Western Australia and Northern Territory is located offshore and is therefore

under Commonwealth control. Western Australia holds the largest reserves, estimated at 90.3TJ (2.4Tcm), with the majority located offshore in the Carnarvon Basin in the west, the Browse Basin in the north-west, the Bonaparte Basin in the north and the Perth Basin in the south west (see Map 1). The onshore Perth Basin is in the centre of the State, but is tiny by comparison with the offshore basins. The offshore gas is piped to onshore processing facilities, after which it is liquefied for export or piped to the gas demand centre around Perth. Appendix 1 gives further details on the gas basins and Appendix 3 on the region's gas pipelines.

5.2 Market size and growth potential

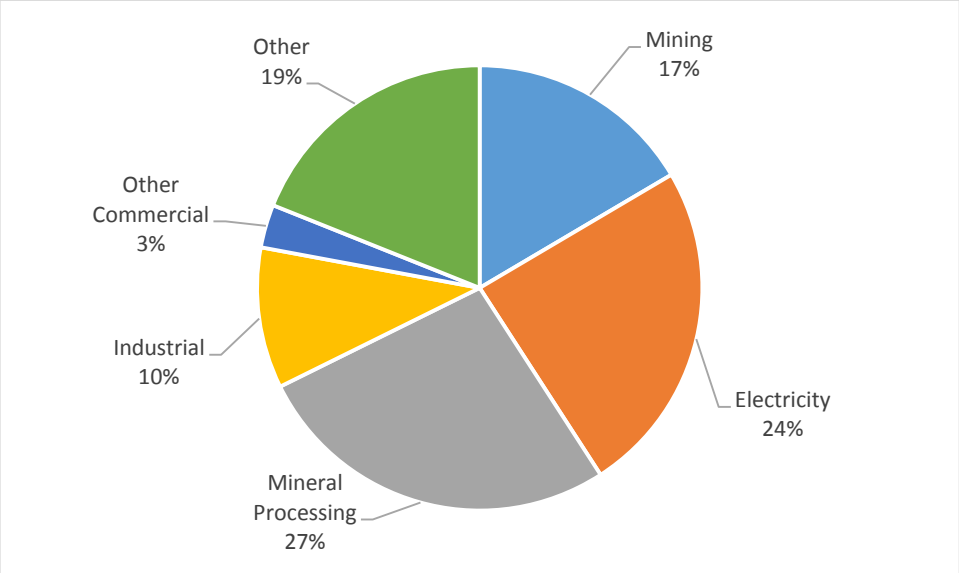
Although the eastern market, which comprises five States in total, is Australia's largest regional gas market, Western Australia is actually the largest consumer as an individual State with total demand of 480PJ (12.8bcm) in 2013, although this includes approximately 120PJ (3.2bcm) used in oil and gas processing (own use) which reduces actual demand to 360PJ (9.6bcm).[51] This local consumption is dwarfed by the gas used in LNG production, which totaled 1,142PJ (30bcm) in 2013,[52] emphasizing the overwhelming importance of exports to the State. Nevertheless, the original plan to develop the North-West Shelf project included an agreement for the construction of a number of gas processing plants to provide gas for the domestic market, with the Western Australia government then providing a gas transmission pipeline to the major markets.

The vast majority of the gas supply to the domestic market in Western Australia, (more than 98%) is provided from gas plants in the north of the State close to the offshore production sites. Gas from the Karratha, Varanus Island and Devil's Creek gas plants is carried to the main markets in the south-west of the State via the main Dampier to Banbury natural gas pipeline (DBNGP). Two other trunk lines, the Goldfields Gas Pipeline (GGP) and the Parmelia Gas Pipeline (PGP) also take gas into the heart of the State to mining and industrial complexes.[53] In addition to the gas piped south from the north-western fields, some domestic onshore production has also been developed in the Perth Basin, although the reserves and output capacity are very small in comparison. According to the Australian Gas Resource Assessment in 2012 the Perth Basin contained 40PJ (just over 1bcm) of 2P reserves and production in 2013 was approximately 150mmcm.

Gas accounts for around half of Western Australia's total energy consumption,[54] with major industrial customers in the mining, power generation, mineral processing and industrial sectors making up the majority of demand (see Figure 13 below). Indeed as few as 8 major consumers, including Alcoa, the Yara Pilbara Ammonia plant, the Worsley Alumina plant and 5 major power stations, account for 90% of total demand, highlighting the concentrated focus of gas usage and also the importance of gas to the domestic economy in Western Australia. From this base, however, demand growth is not expected to be very strong, with the recent Statement of Opportunities for the State only forecasting an increase of 0.4% per annum to 2023, implying a total demand increase of approximately 1bcma over the next 9 years.[55]

[51] Energy Quest (2013)
[52] Ibid.
[53] IES (2013)
[54] IMOWA (2014), p.30
[55] Ibid, p.7

Figure 13: Split of demand by sector in Western Australia (2012)



Source: IMOWA

However, although the potential outlook for demand growth is relatively slow, the Western Australia government has always been keen to ensure that gas is available for domestic customers at competitive prices. As mentioned above, initially an agreement was put in place with the NWS project to co-ordinate supply to the domestic market in tandem with LNG exports, and five "foundation" customers signed the first long-term contracts in 1984. During the 20 year duration of the contracts the price remained relatively stable at approximately A$2.25/GJ (US$2.23/MMBtu), but once they expired in 2004 prices started to move up towards a significantly higher range of A$4-6/GJ (US$3.95-6.05/MMbtu). As a result, in 2006 the Western Australia government introduced a gas reservation policy, or DMO, which has been aimed at ensuring that, although domestic gas prices continue to be set on a market basis there should always be enough gas to avoid a shortage of supply and a dramatic spike upwards in the price.

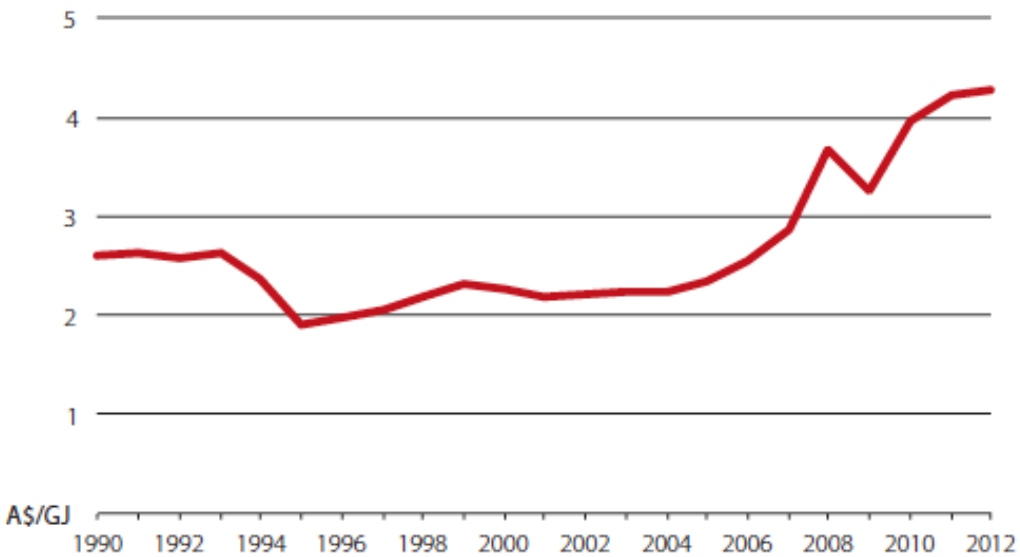
In essence each LNG project is required to reserve 15% of its gas for domestic use, unless an alternative agreement has been reached with the State government, and must make it available on market terms to consumers in Western Australia. The gas does not necessarily need to come from the LNG project itself, but an equivalent volume must be sourced and made available either from the LNG operator's domestic production or via a swap arrangement with other producers.[56] In reality though only one project, the North West Shelf scheme, has actually been forced to meet the full DMO requirement, as other projects have managed to negotiate separate and less onerous agreements with the Western Australia government. Pluto, Gorgon and Pluto have DMOs as part of their agreements with the State. The Pluto project, for example, has no DMO on Train 1, but it kicks in from the start-up of train 2 (or potentially after 5 years of LNG production) and the Gorgon project will sell 15% of its gas domestically. The reason for this somewhat flexible attitude towards the DMO in Western Australia is two-fold. Firstly, it is because the DMO can only apply to projects in areas under state jurisdiction, in other words onshore or in state waters. As a result, project operators have been tempted to suggest that they might opt for floating LNG projects in order to develop their projects in federal waters and thus void the DMO, with a clear negative implication for jobs, taxes and economic

[56] Department of Industry and Bureau of Resource and Energy Economics, Study on the Australian Domestic Gas Market, 28th November 2013, p.119 See note 53

growth in Western Australia. A second reason has been that the government of Northern Territory has decided not to impose any reservation policy on projects developed within its remit in order to encourage the growth of Darwin as an LNG hub. This has already had an impact on development plans, with the Ichthys project deciding to place its liquefaction plant in Darwin rather than in the geographically closer Western Australia, [57][58] (while the offshore fields are in the Commonwealth offshore waters) leaving the Western Australia government with a question mark over its future strategy as it reviews its DMO policy over the next 12 to 18 months.

The Western Australia government has a difficult decision to make because on the one hand it could lose LNG developments within its territory if it imposes a DMO on each project, while on the other hand it risks undermining its domestic economy if gas prices rise sharply or if gas becomes in increasingly short supply. Interestingly, though, the introduction of the DMO in 2006 has only been partially successful in holding down gas prices, as can be seen from the graph below (Figure 16). as mentioned above, from 1984 to 2004 gas prices were stable at A$2.25/GJ (US$2.23/MMBtu) but have since risen steadily to reach A$4.30/GJ by 2012 (US$ 4.25/MMBtu) and A$5.05/GJ in Q4 2013 (US$5.00/MMbtu), driven by rising production costs, the mining boom and increasing international LNG and oil prices. [59] Furthermore, Western Australia may soon see even higher prices and a shift in demand when cheap domestic supplies decline with the expiry of the long-term gas contract that underpinned the Dampier to Bunbury Pipeline. New contracts are currently being agreed at A$5-6/GJ (US$ 4.9-5.9/MMBtu) and forecast prices for the next decade are expected to be in the range A$6-9/GJ (US$5.9-8.8/MMBtu)[60].

Figure 14: Western Australia domestic gas prices 1990-2012



Source: BREE (2013a) p34

[57] The Ichthys project decided to lay a pipeline to Darwin rather than the geographically closer Western Australia, influenced by the fact that the Northern Territories does not have a reservation policy. The only economically viable shore-landing in Western Australia was the existing LNG facilities at Karratha, which was not closer than Darwin, alternatively the project could have been developed on a greenfield basis, in a remote location without infrastructure, at higher cost.
[58] Coleman (2013)
[59] BREE (2013b)
[60] BREE (2013b)

As a result, domestic prices in Western Australia are increasingly related to the netback equivalent that project developers can expect to receive from LNG exports. The correlation is not perfect because of the distorting impact of the DMO, but as can be seen from Table 6 below the current level of domestic prices is approaching the export netback from the NWS project, once transport costs to the Perth market have been taken into consideration. With new contracts set to be priced in a range above US$6/MMBtu, it is becomingly increasingly clear that Western Australia consumers will be forced to accept gas prices that are set with reference to the levels that are set for sales to consumers for Australian LNG in Asia. The choice for the Western Australia government is therefore clear – accept higher prices in the domestic market or impose a stricter DMO on new LNG projects and risk losing them to FLNG projects in federal waters or to rival states, with the relevant consequences for tax revenue generation and economic development in Western Australia. Although no final decision has yet been made, negotiations with new projects such as Gorgon would suggest that the authorities will attempt to retain some domestic gas obligation but ultimately this may not be enough to halt the increase of domestic gas prices towards international levels. This outcome will not go unchallenged, as an interest group, the DomGas Alliance, has been formed to represent the interests of natural gas users, infrastructure investors and producers in Western Australia to campaign for the reservation of at least 15% of gas produced for domestic use. Nevertheless, it would seem that price parity with LNG netbacks is the most likely outcome.

As the Western Australia domestic market becomes increasingly linked to international price drivers as well as to the domestic supply and demand balance, the Australian Energy Market Operator (AEMO) and Retail Energy Market Company Limited (REMCo), in tandem with the WA Independent Market Operator,[61] have started to look at the development of a short term trading market in Western Australia in order to promote a more liquid market place. Gas in Western Australia currently operates under a contract carriage model[62] and is dominated by bilateral contracts for gas, so there has been very little competition in the production or transport of gas and no transparency in gas prices or movements. Even though a recent REMCo study[63] concluded that a short-term traded market would be unlikely to deliver net benefits at this time, two gas trading initiatives have been introduced in Western Australia; Gas Trading Australia Pty Ltd has started to operate a "spot market" mechanism based on the brokerage model which was developed to provide gas users with a gas trading platform to balance their excess and deficits and Energy Access Services Pty Ltd has started to operate an automated Energy Trading Platform, which operates like the Australian Securities Exchange where buyers and sellers can place bids for different periods. However, even with these platforms in place, together with a new Gas Bulletin Board and a Gas Statement of Opportunities, the limited number of gas buyers and sellers and low level of future liquidity means that gas is likely to continue to be traded on a bilateral basis and that any gas trading initiatives will remain at the margin, for balancing purposes only.

5.3 The Northern Territory – a very small domestic market, dominated by LNG export strategy

Data on the gas market in the Northern Territory is relatively sparse, reflecting the small size of the volumes sold and the overall focus on LNG exports. Figure 8 above, taken from BREE's gas market report in 2013,[64] suggests that total demand in 2011-12 was approximately 60PJ (1.6bcm), roughly

[61] http://www.imowa.com.au/gas-information-services-project---gisp/timelines-and-key-dates
[62] A contract of carriage model is where the seller agrees a contract between a carrier of goods that defines the rights, duties and liabilities of parties to the contract
[63] REMCO (2013)
[64] BREE (2013a)

split 50% to the mining sector and 50% to power generation. However, as this overall figure includes gas used to fuel the LNG plant it is probably more appropriate to use the data from the Australian Energy Regulator which would suggest a much lower figure of 22PJ (0.6bcm), based on production figures from the State's two gas basins, the offshore Bonaparte Basin (20PJ of output, approx. 0.55bm) and the Amadeus Basin (2PJ, approx. 0.05bcm). In either case, though, demand is set to remain fairly flat as the state government focuses more on an export-oriented rather than domestic gas policy.

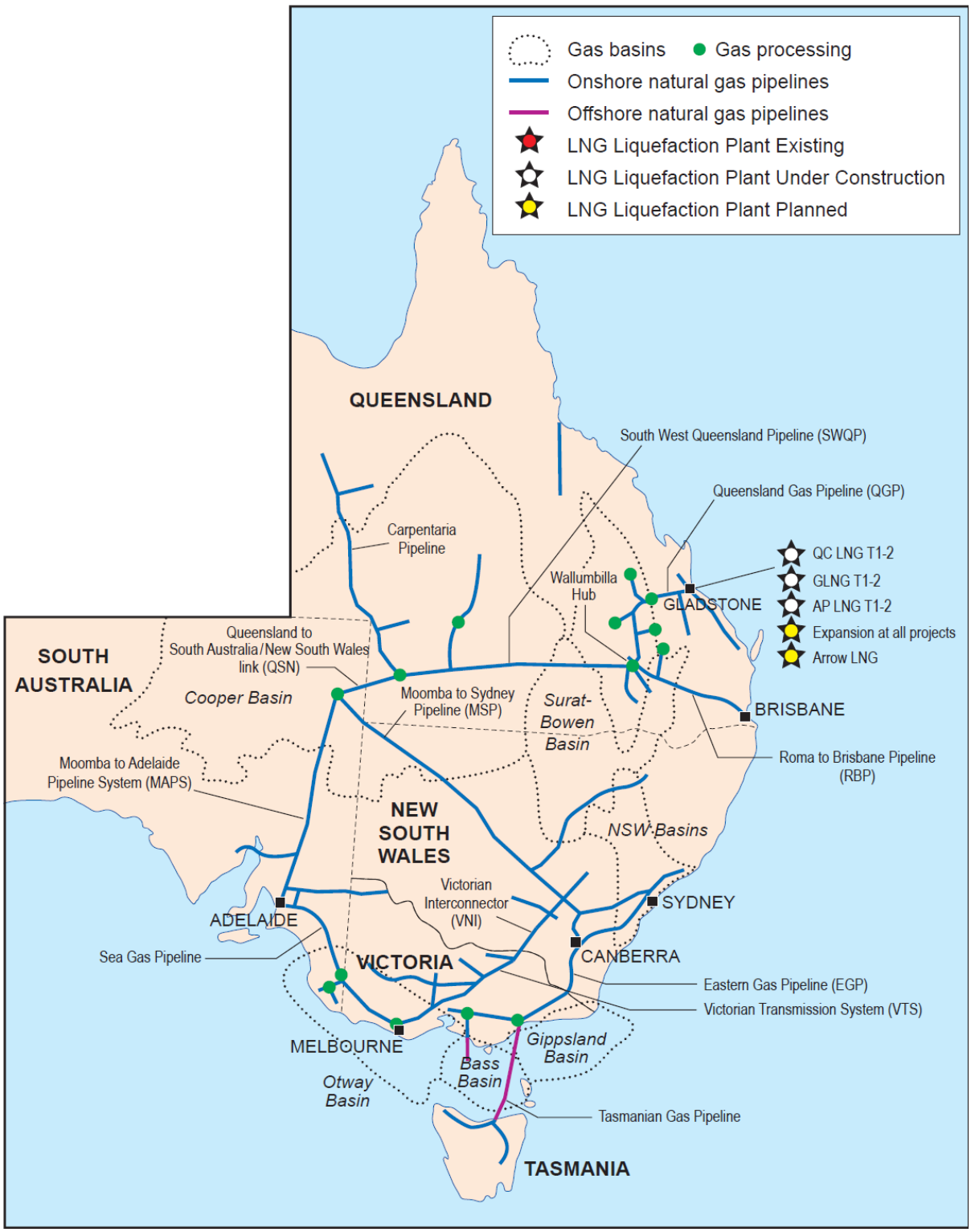
This situation has partly resulted from the Northern Territory Government's policy to stimulate gas development without a gas reservation policy. The continued supply of gas to the domestic market from the Bonaparte Basin has therefore been driven by price, not regulation, with the small size of the domestic market also being an obvious catalyst for the focus on export projects and their price implications. The Chief Minister has even gone so far as to state that the Northern Territory has a "use it or lose it" policy in regard to the development of onshore gas and that any DMO would reduce its competitive advantage relative to Western Australia. As mentioned above, the State government is pushing for Darwin to become an LNG hub by lobbying for the region to be the service hub for Woodside and Shell's Prelude FLNG and to be the centre for the location of additional LNG trains beyond the existing Darwin LNG project[65].

One possible shift in strategy with regard to the domestic market, however, is the suggestion that Northern Territory pipeline infrastructure could be connected to the pipeline systems in Queensland or South Australia, with the ultimate goal not of importing gas to meet local demand but of increasing exports to the gas-short market in New South Wales.[66] This would potentially allow increased gas supply from the Timor Sea and the Bonaparte Basin (which is currently only linked to the NT domestic market) to reach the larger gas markets, and possibly even the LNG projects, in the east of the country. Although the project is only at an early stage of feasibility assessment, it again underlines the focus of the NT gas industry and government on export sales rather than domestic consumption within the state.

[65] Fullerton (2013)
[66] "Australia's APA eyes gas connection from north to east", http://www.platts.com/latest-news/natural-gas/sydney/australias-apa-eyes-gas-pipeline-connection-from-27952042

6. The Eastern gas market and the impact of imminent LNG exports

Map 2: Eastern Australian Gas Infrastructure

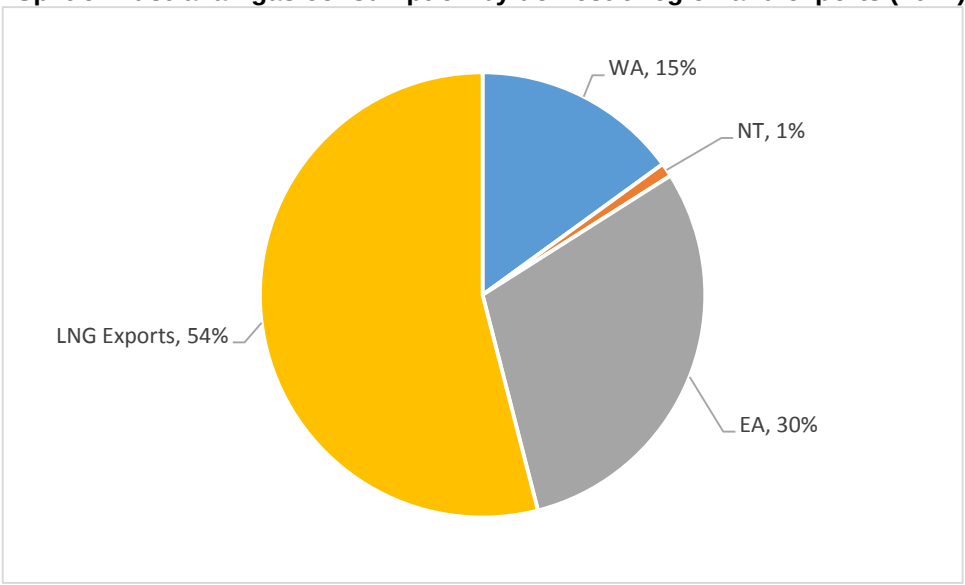


Source: OIES

6.1 Introduction

In stark contrast to the largely export-driven development of west and north Australian gas, the market in Eastern Australia has historically had an entirely domestic focus, with the five states in the region linked by a series of inter-state pipelines to domestic onshore gas production that has provided energy for the residential, commercial, industrial and power generation markets. As can be seen in Figure 15 below, although LNG exports dominate Australian gas sales, Eastern Australia is by far the largest domestic gas market in the country, currently accounting for 30% of demand.

Figure 15: Split of Australian gas consumption by domestic region and exports (2012)



Source: BREE (2013b), p.37

However, this situation is set to change from 2014 as Eastern Australia's gas reserves will for the first time be sold into the export as well as the domestic market, as the first of three LNG projects currently under construction comes online. The imminence of this significant change in the eastern gas market combined with a level of uncertainty over the balance of gas availability for the two markets is already having an impact, both on domestic price levels and on the ability of consumers to access gas under the long-term contracts that they have been accustomed to signing. As we will describe below, this major shift in the supply/demand patterns in the region, within which the five constituent states all have sharply contrasting positions, is leading to significant political and economic debates that have yet to be fully resolved. Although it seems very unlikely that the current plans for developing three 2-train LNG projects at Gladstone in Queensland will be undermined, the continuing discussion about the balance of export and domestic sales and the impact of sourcing much of the gas requirement from unconventional sources such as coal seam gas and shale gas could well determine whether further expansions and new projects are contemplated.

6.2 Overview of the East Australian gas market

The total size of the East Australian gas market in 2012 was just under 700PJ (18 Bcm), but as can be seen in Table 6 and Figure 16 below the sizes and shapes of the five regional markets vary considerably as does the supply and demand position within each State. Indeed the fundamental contrast is between three States, Victoria (VIC), South Australia (SA) and Queensland (QLD), who are net exporters of gas, New South Wales (NSW) that is one large market and a large importer, and

Tasmania (TAS) that is one very small market and therefore has little impact on the overall analysis but which imports much of its gas from neighbouring Victoria.

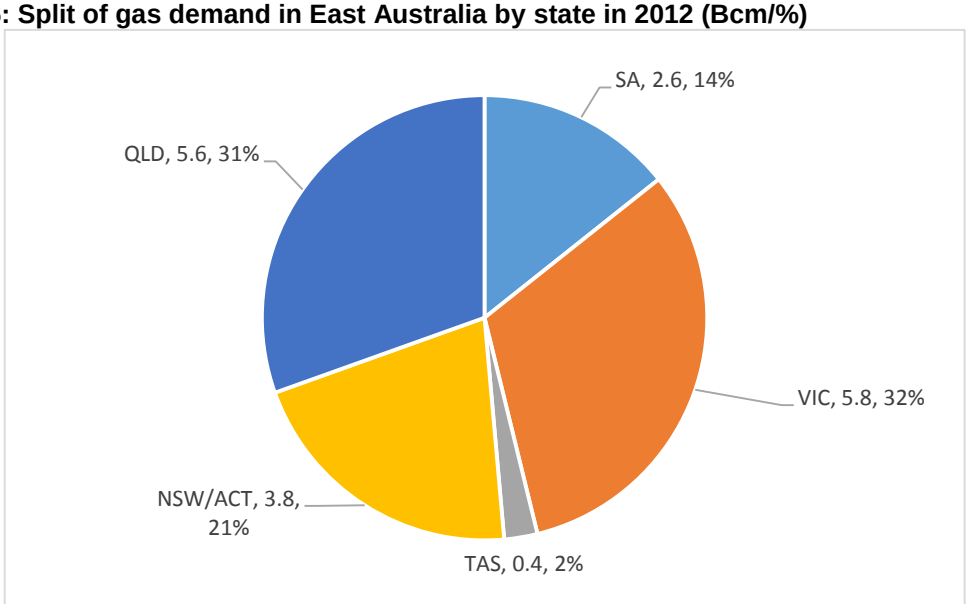
Table 6: Summary of East Australian gas market by state (2012 and 2030E)

bcm	2012			
	Power	**Res&Comm**	**Industry**	***Total***
SA	1.7	0.3	0.6	*2.6*
VIC	0.4	3.3	2.1	*5.8*
TAS	0.3	0.0	0.1	*0.5*
NSW/ACT	0.9	1.1	1.8	*3.8*
QLD	2.1	0.2	3.3	*5.6*
Total	5.4	5.0	8.0	*18.3*
Total Demand =====>		**18.3**		

Source: AEMO 2013a

As can be seen in Figure 16, Victoria and Queensland both account for around one third of the region's overall gas demand, followed by New South Wales with 21% and South Australia with 14%. Figure 17, though, shows that both of the larger consuming states produce significant amounts of gas over and above their local requirements, with Victoria having a particularly large surplus of over 4Bcm. Essentially this entire excess, as well as exports from Southern Australia and Queensland, are sold into the New South Wales market, which buys 95% of its gas from outside the State. As will be discussed later, this is one reason why the changing dynamics of the region's gas sales towards the export market are having a very significant impact in New South Wales.

Figure 16: Split of gas demand in East Australia by state in 2012 (Bcm/%)



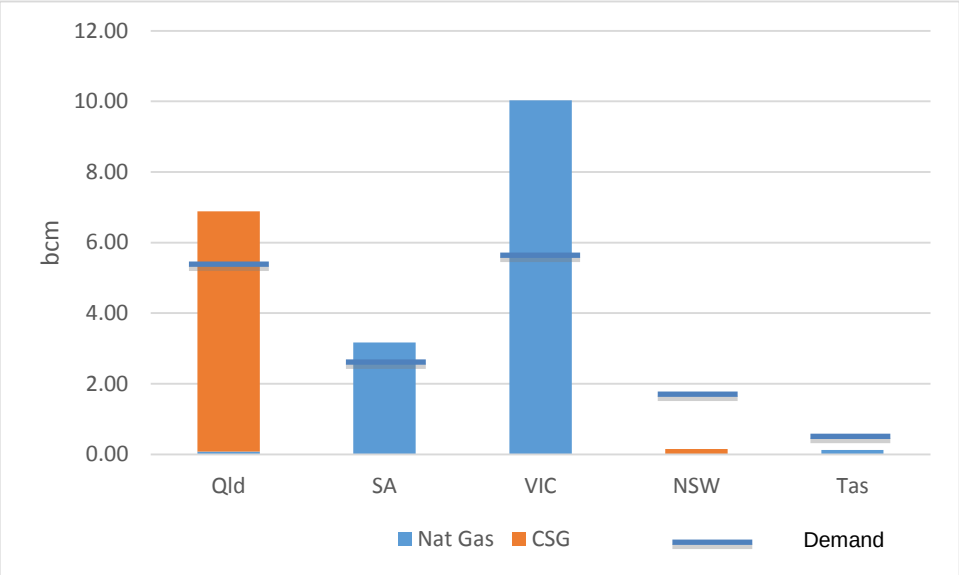
Source: AEMO 2013a

One additional theme that emerges from Figure 17 is the contrast between production from conventional gas fields and output from CSG Resources. Historically eastern Australian gas production has come from traditional onshore gas fields in the Cooper Basin (largely in South

Australia but also in Queensland) and from offshore fields in Victoria's Gippsland Basin. However, the emergence of CSG as a rich source of new supply from the early 2000s, and in particular from 2006, initially replacing a decline in the output from the Cooper Basin before catalyzing a surge in domestic supply and ultimately, because of the size of the resource base (see later discussion), encouraging the development of the LNG projects in Queensland.

Figure 17: Gas production versus demand by state in East Australia

Source: APPEA production data for 2012



The individual markets in the region and their projected growth trajectories are described below:

In **Victoria**, the largest of the gas markets, the residential and industrial sectors dominate, while power generation has been slow to increase gas utilization due to the availability of domestic brown coal reserves which account for 85% of the fuel input for electricity generation in the State. According to the GSOO Natural Gas Forecast, published in 2013[67], this situation is unlikely to change unless the government changes its view on the implementation of a carbon tax, which has recently been removed having been introduced by the previous administration. Total gas demand currently stands at 5.8Bcm after a 1.5% p.a. fall in demand between 2008 and 2012, largely due to lower large industrial demand and reduced gas use in power generation because of an overall decrease in electricity demand. However, the AEMO has forecast in its National Gas Forecast (2013) that between 2014 and 2018 annual gas demand will rebound at a rate of 0.8% pa. This increase is due to rising residential and business demand in response to growing household incomes; increasing dwelling stocks, and lower gas price growth. Equally importantly, though, it is anticipated that the State's gas production from its traditional offshore reserves base will also go into decline in the next decade, altering the supply-demand balance and the likely pricing picture.

In contrast the growth of the **Queensland** gas market over the past decade has been driven by a state government decision to encourage its use as a fuel for power generation. The Queensland Gas Scheme was introduced in 2005 and mandated that electricity retailers should purchase at least 15% of their power from gas-fired electricity generators, which led to the rapid growth of gas use in the

[67] AEMO (2013a)

State. Infrastructure was built to supply power stations, and other industrial users were encouraged to increase their gas usage, with the result that between 2008 and 2012 annual domestic gas demand rose by 7.9%/year to reach 5.6 Bcm. The future outlook seems much less clear, with the AEMO foreseeing a decline of 4.2%/year until 2018 due to an increase in the gas price as long term gas contracts expire, which is expected to lead to a fall in gas use in the power sector. As a result gas could become less available for domestic use due to potential diversion towards LNG projects.

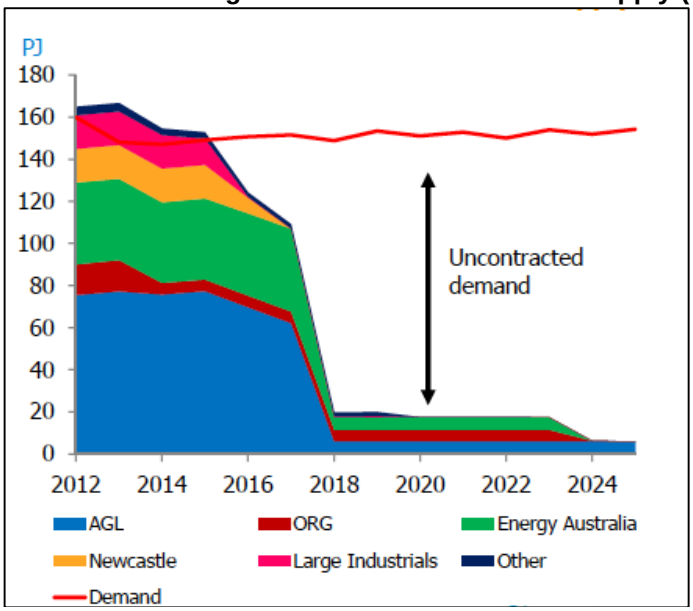
A similar story of declining demand in the short to medium term already seems to be playing out in **South Australia,** where between 2008 and 2012 overall gas demand fell by 3.0%/year due mainly to a decrease in gas-fired generation. This resulted both from a decrease in total demand for electricity and also from an increase in wind and rooftop solar. A further decline is forecast by AEMO between 2014 and 2018, with annual gas demand being estimated to fall at of 5.5%/year, with a continuing driver being reduced use in the power sector caused by the rising price of gas and the impact of low cost wind generation and other renewable energy sources.

Of the gas importing states **Tasmania** offers a small but similar example to Queensland, with rising demand for gas in power generation since 2008 followed by a rapid decline and then a gradual future recovery. However, despite this forecast recovery, which will be led by industrial growth, demand for gas in the state is expected overall to decline, primarily because higher gas prices are likely to reduce consumption from the power generation sector.

Finally it is perhaps no surprise, given the analysis above, that the largest gas importing State, **New South Wales**, is facing increasing concerns about gas shortages over the next few years, reflected in the contractual position of many of the state's largest customers. New South Wales's large industrial users are the main consumers, followed by an extensive residential sector, but the power sector also uses a significant volume due to recent switching from coal. Total demand in 2012 was 3.8 Bcm, and this is forecast to rise only slightly in future, although once again this overall picture masks an initial decline, especially in the power sector as tight supply in the eastern market as a whole may mean that higher prices preclude gas use for electricity generation and also inhibit industrial demand.

However, the key short-term issue in New South Wales concerns the Gas Sales Agreements (GSAs) that have formed the foundation of the State's gas imports from its neighbours over the past twenty years. Historically these have been long-term contracts lasting for as long as 30 years, although recently the length has been declining towards a more normal average of around 15 years, with the supply underpinned by Gas Transport Agreements (GTAs) which ensure the delivery of the gas via one of the many regulated and unregulated pipelines in Eastern Australia (see Appendix 3 for details). Unfortunately for customers in New South Wales, the changing dynamics of the Eastern Australia gas market, and the new opportunity provided by LNG exports, has meant that suppliers have become less keen to commit to long-term domestic supply contracts, with the result (shown in Figure 21) that by 2018 New South Wales will have very limited security of supply as the majority of its existing contracts will have expired.

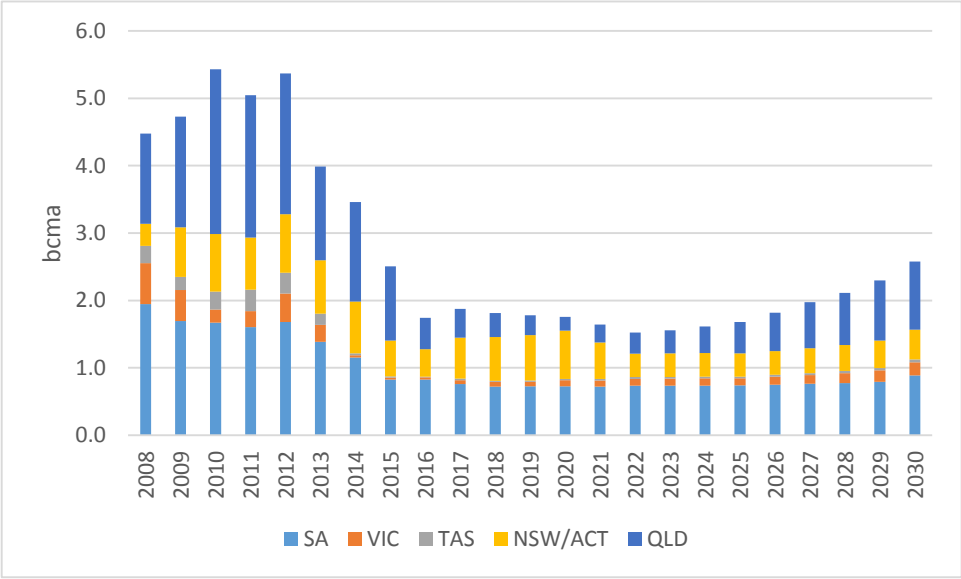
Figure 18: New South Wales and ACT gas demand and contracted supply (2012-2024)



Source: Santos (2013), p8

This picture highlights the main dilemma for all the eastern markets, namely the short-term uncertainty over how supply and demand will be matched and at what price. This is reflected not only in the NSW contract issue but also in a theme that has been recurrent throughout the discussion of demand in the various States, namely consumption in the power generation sector. As Figure 19 shows clearly, there is a broad anticipation that gas demand in the power sector will fall sharply over the next few years in Eastern Australia, with the main cause being cited by the various government agencies and forecasting units as a potential lack of gas availability due to the higher prices available for LNG exports.

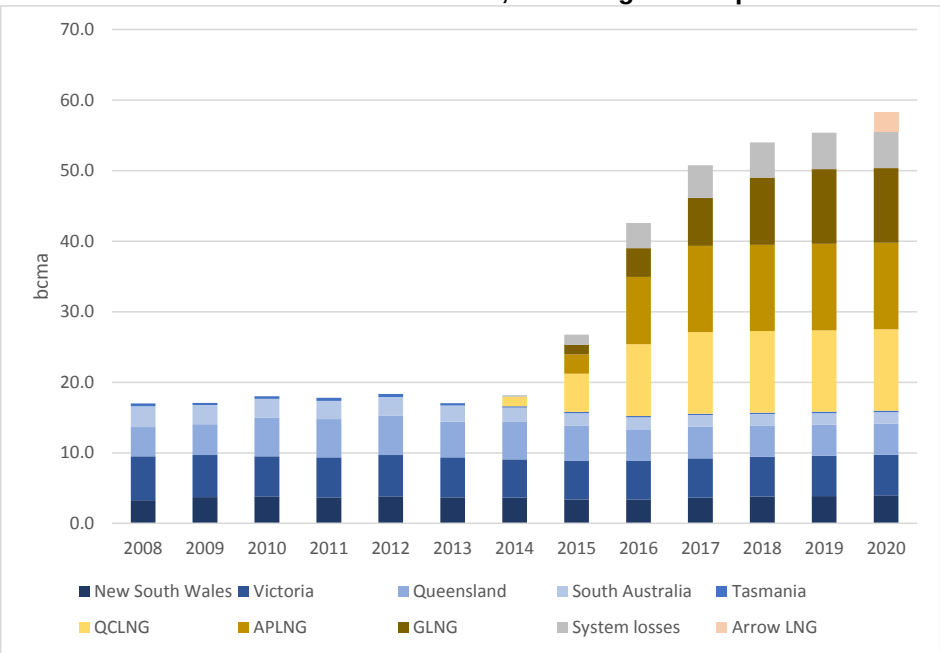
Figure 19: Forecast of gas use in Eastern Australia power sector



Source: AEMO (2013a)

This short-term decline in demand, and the very slow future recovery expected in most states, has led to discussion of a gas shortfall which has been estimated to be as much as 4Bcm/year by 2030.[68] This forecast is based on two key assumptions, namely that higher gas prices will dampen demand and that gas will be in short supply due to the need for feed-gas to supply the build-up in LNG output expected at the regions' three new LNG facilities (see figure 20 below). However, it is questionable whether either of these issues will have the long-term impact suggested by the Australian authorities. Australia is not the first market to suffer from higher gas prices, which tend to have a short-term impact on demand before the economy adjusts to the new pricing environment, in particular because domestic supply is likely to increase if prices are higher. Similarly, the feed-gas issue for the LNG plants is also likely to be a relatively short-term phenomenon until gas production from Coal Seam Gas developments reaches peak output towards the end of this decade. Nevertheless, the issue of failure to renew long-term contracts is a concern, but could be partially alleviated by the creation of more liquid trading hubs in their place in order to catalyse the market reaction to higher prices described above.

Figure 20: Demand forecast for EA market to 2020, including LNG exports



Source: AEMO (2013a), Company reports, Authors' estimates

6.3 Gas resources and production in Eastern Australia

Eastern Australia is the historic heartland of Australia's gas industry and still has significant remaining reserves and resource potential. As Table 7 shows, 2P (proved and probable) reserves total 1150-1330 Bcm, while 2C resources have a wider range but could be as high as 1,100 Bcm, according to a 2013 estimate. Furthermore, the region also contains significant shale gas resources that have not, in the author's opinion, been fully reflected in this table. Technically recoverable resources have been estimated as high as 7.75 Tcm,[69] although only 10-20% of this would be likely to be ultimately recoverable on a commercial basis.

[68] BREE, East Australian Gas Market Study, 2013, p.19
[69] BREE (2013b) p.27

Table 7: Eastern Australia gas reserves and resources estimates

Bcm	2P Reserves		2C Resources	
	AGRA (2012)	RLMS (2013)	AGRA (2012)	RLMS (2013)
Conventional Gas				
Offshore Victoria				
Gippsland	141	101	101	28
Otway	27	19	14	3
Bass Basin	7	6	13	9
Onshore SA/Queensland				
Cooper/Eromanga/Warburton	27	48	3	129
Surat/Bowen/Adavale	14	4	0	0
Onshore NSW				
Gunnedah	0	0	0	0
Clarence-Morton	0	0	2	0
Total Conventional Gas	**217**	**178**	**133**	**170**
Coal Seam Gas				
Queensland				
Surat/Bowen	857	1081	0	650
Galilee	0	0	0	8
NSW				
Gunnedah	39	37	0	90
Clarence-Morton	11	12	0	65
Gloucester	17	17	0	0
Sydney	7	7	0	14
Total NSZ CSG	*75*	*73*	*0*	*169*
Total CSG	**933**	**1154**	**0**	**819**
Shale/Tight Gas				
Cooper	0	0	57	110
Total Gas	**1149**	**1332**	**190**	**1099**

Source: Australian Gas Resource Assessment 2012 (AGRA), Resource and Land Management Services (RLMS) – Eastern Australia Gas Reserves and Resources 2013

As can be seen, the majority of the region's conventional reserves are located in the Cooper/Eromanga basin that straddles South Australia and Queensland and the Gippsland, Bass and Otway basins offshore Victoria. These areas have been producing for 35-40 years, but as can also be seen from Figure 24 the future of gas production in Eastern Australia will be based on the much larger

reserves of CSG that are mainly located in the Surat/Bowen basin in Queensland. Indeed, depending on the estimate used, 75-80% of Eastern Australia's total 2P gas reserves are located in this region alone. However, a key point is that the owners of the LNG projects in Queensland largely control the CSG reserves that they are developing to supply the plants, as can be seen in Table 8. According to a recent report by BREE on the East Australian market the three main LNG projects currently under construction control over 750 Bcm of CSG 2P reserves, while the addition of the reserves held by the Arrow project takes this to almost 1 Tcm. This means that, even on the high case reserve estimate in Table 7, only 25% of the estimated total reserves would be available for the domestic market.

Table 8: CSG reserves and resources controlled by four major LNG projects in EA

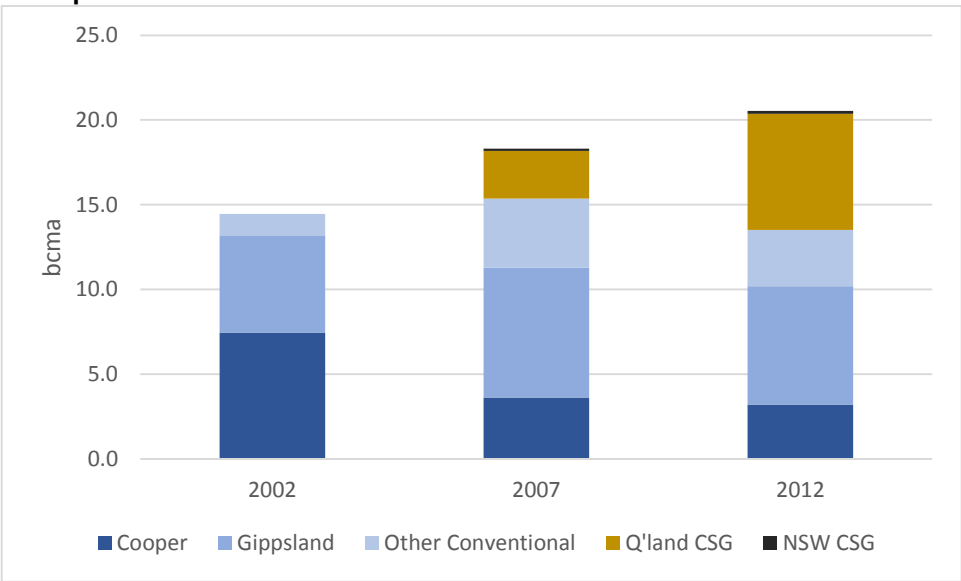
		Reserves			Resources	
bcm	**Capacity (mtpa)**	**1P**	**2P**	**3P**	**2C**	***Total 3P+2C***
APLNG (ConocoPhillips, Origin)	9	40	347	418	95	*513*
QCLNG (BG)	8.5	79	273	296	117	*413*
Gladstone LNG (Santos)	7.8	47	140	177	43	*220*
Arrow LNG (Shell)	8	14	214	332	65	*398*
Total	33.3	180	974	1224	320	*1544*

Source: BREE (2013a)

This bias of reserves towards the LNG producers is important for two reasons. Firstly domestic production from conventional resources is in decline, as can be seen in Figure 21. Although it is possible that this fall in output could be slowed as gas prices rise to incentivize more production, it does appear that fields in the Cooper Basin and the offshore Gippsland Basin are in decline (although efforts are being made in both areas to stem this).[70] Indeed at current production levels the total reserves life of conventional gas in Eastern Australia (based on 2P reserves estimates) is only around 13 years, with even the Gippsland Basin having a reserves life below 15 years. Although this overall figure does increase to 25 years if 2C resources are included, it is nevertheless clear that CSG is set to play an increasingly important role in supply to the domestic market. CSG production already contributes almost all of the gas production in Queensland, but with the emergence of the opportunity to sell it as LNG exports rather than into the domestic market, producers are being tempted to divert gas away from domestic consumers. Again, this incentive could change as domestic prices rise, but the clear implication is that local markets are going to have to pay more for gas. Indeed the only factor that may have been restraining prices to date is the long-term contracts that have been in place, and as these expire it is likely (and indeed is already the case in many instances) that prices for new gas will reflect market reality.

[70] Unconventional (shale gas) resources are being explored in the Cooper Basin, while new fields such as Kipper and Turrum are being brought online in the Gippsland Basin from 2016/17.

Figure 21: Gas production in Eastern Australia to 2012



Source: APPEA annual production statistics for 2002, 2007 and 2012 [71]

One final point that reiterates the shifting dynamics of the East Australian gas market is that the three major suppliers of gas into the local market - Origin Energy, AGL and EnergyAustralia - control considerably less than 10% of the region's gas reserves. Indeed EnergyAustralia's reserves are so small that they are only included in the "Other" category on the chart. These three companies supply 87% of the retail gas market in Eastern Australia and have traditionally relied on secure supply from upstream producers with no other option than to sell to domestic customers. However, this situation has now changed dramatically due to the emergence of an export option that offers more attractive prices and margins.

In the next sections we will describe the three main LNG projects, the main issues with their gas supply options and why they are affecting the domestic market and the impact on gas prices in Eastern Australia. We will then conclude on the outlook for LNG exports from CSG reserves in the region. However, first we will briefly review the key issues related to the development and production of Coal Seam Gas, as they are particularly relevant when discussing the uncertainties facing the LNG projects, and as a consequence, domestic customers in Eastern Australia.

6.4 Coal Seam Gas development issues in Eastern Australia

Although the CSG resource has been exploited for some time to provide gas supply to the domestic market, the challenges involved in expanding production for LNG exports are significant. They include not only operational issues involving the rapid application of new technology, the intensive drilling of thousands of wells over large areas and the ultimate deliverability of gas from those wells but also the need in some states to address environmental, governmental and popular concerns over the impact of the industry on the environment, resources (particularly water) and alternative land use. It would appear that both these issues are having a more serious impact than anticipated at the time when projects where first approved, with the implication that CSG production could be delayed, necessitating the diversion of alternative supply from the domestic market to the new LNG facilities as they enter their start-up phase.

[71] *http://www.appea.com.au/industry-in-depth/industry-statistics/*

CSG operational challenges are considerable

Coal seam gas (also known as coal-bed methane) is produced from underground coal seams that have often been associated with previous mining activity. The principle behind the extraction of CSG is that wells are drilled down into the coal beds, which are normally saturated with water, and as the water is released to the surface so the gas in the seam is released from natural fractures (cleats), de-sorbs from the body of the coal itself and is able to flow out of the well. Clearly this process involves the use of significant quantities of water, and the management of this is a major issue, which is discussed below. From a gas production perspective, though, there are other operational challenges, not the least the fact that coal seam reservoirs do not allow extensive migration of gas, meaning that individual well flow rates are relatively low and therefore multiple wells need to be drilled in relatively close proximity. [72] Furthermore the variability of well results is high, with for example, wells in the Surat and Bowen Basins being estimated to produce at an initial rate of 0.5-2.2TJ/d (0.45-2 Mcf/d) - a wide range in itself which causes problems for producers trying to estimate future production from a field.

As a result CSG development, is more of an industrial process than a traditional field development, meaning that more than 60% of the cost of developing a CSG field is related to infrastructure such as compression, gas gathering and water treatment facilities. As such, a coal seam gas LNG project, such as Asia Pacific LNG, will have to drill around 20,000 wells over the life of the project, leading to an extended capital expenditure profile. Each of the shallow wells, which can be drilled in around 5 days, needs to be connected to the pipeline infrastructure, and the gas then transported to the liquefaction plant on Gladstone Island, a distance of 340-450 km depending on the exact field location. Initially, the three Gladstone CSG projects were each planning to build their own pipeline infrastructure, but cost and operational pressures have now forced them to cooperate, with Santos and BG in mid-2013 agreeing to connect the two gas pipelines that will feed their projects. This cooperation between the different projects could also lead to shorter gas supply ramp-up times and sharing of the feed gas pipeline network will also mean that more potential gas suppliers will be available for each project. However, despite this increased potential for gas sharing Queensland Curtis LNG is still being forced to contract for higher cost conventional gas as CSG reserves are proving harder to develop, and increasingly expensive wells are required. Community opposition, discussed below, has also made land access difficult, and in some cases off-limits.[73]

A further issue that could cause delays in the start-up of the plants is that operators have to learn how to process the lean gas[74] from the coal seams in the liquefaction process. Essentially the dynamics of developing the CSG resource as LNG feedgas has specific challenges with implications not only for the timing of first production but also for the rate with which output can be ramped up.

Community concern over environmental issues is becoming a political issue

CSG has been produced and used in Australia for nearly 30 years, but community concern has only arisen recently with the prospect of the rapid expansion of the industry. The issue of CSG is particularly emotive in eastern markets, with concerns focusing primarily on the impact on water resources and the environmental in general, with a lack of public trust in the government and the gas industry being inflamed by active media coverage. As a result in 2013 the New South Wales Chief Scientist & Engineer was asked to produce a report - the Independent Review of Coal Seam Gas

[72] Unsworth, N (2010).
[73] Natural Gas Info www.natgas.info "Can Australian LNG projects stay competitive?", May 2013
[74] Coal seam gas has a lower heating value than gas from associated or non-associated gas reservoirs. The LNG from the coal seam LNG plants will have a gross heating value of ~ 1000 btu/scf when compared to ~1100 btu/scf from the LNG projects in the North-West of Australia.

Activities in New South Wales[75] - which provided a comprehensive analysis of the concerns surrounding CSG.

Exploration for CSG started in Queensland in the 1970s in the Bowen Basin, and by the early 1990s had extended to the Surat Basin in the State's south west. The industry expanded rapidly but in response, in 2009, the anti-CSG movement in Queensland was established. CSG subsequently became an issue in the August 2010 federal election where farmers, landowners, environmentalists and political groups such as the Australian Greens united over the impact of CSG on water, the environment and landholder rights. Indeed in late 2010, over 160 community groups against CSG joined together and the "Lock the Gate Alliance" was incorporated to represent their collective interest. This campaign involved landowners locking their gates to CSG companies and refusing to negotiate access to their land, and any potential gas producers having to take landowners to arbitration to gain access to CSG licences. In Queensland the issue has been mitigated by the vast land area and low population density, an as a result the main focus of the current debate has been in New South Wales and Victoria, where population density is higher and there is a more active conflict between farmers and gas producers. However, despite the regional differences in attitude it appears that the issue could become a national one as the federal government has become involved on key topics such as water usage and environmental impact.

Water is the main issue

Water is at the centre of the argument against CSG, both because of the large volumes of saline water which have to be pumped from each well to extract the gas, and also to a lesser extent because the scarce fresh water resource is used in the fracking process that is in some wells used to crack the coal seams to improve the flow of gas. The storing and disposal of the wastewater is tightly regulated, but concerns about spills and the contamination of groundwater reservoirs remain, and are also connected to the use of chemicals and other fluids in the fracking process. In terms of water consumption, it is estimated that CSG production in Queensland will consume approximately 300GL/year, which is around one sixth the use in the agricultural sector but still enough to make it the second largest consumer in the state.[76] In a relatively dry environment such as Australia water is clearly a precious resource and as a result any economic development that places water resources at risk quickly becomes a very emotive issue, and this has certainly been the case with the CSG industry.

Land owner issues

Landowner issues are another source of antagonism surrounding CSG. In Australia, land and associated resources belong to the Crown, and people purchase the right from the States and Territory to hold tenure over land. The Crown and approved third parties have the legal right to access "private" land for the purpose of the exploration and production of resources. Since communities have often misconstrued what it means to "own land", residents have raised issues concerning the lack of rights of landowners, and specifically a lack of consultation and compensation for what they feel are changes to their rights over their land.

An initial response to this issue has been seen in New South Wales, where in March 2014, AGL and Santos signed the *Agreed Principles of Land Access* with NSW Farmers, Cotton Australia and the NSW Irrigators' Council, in relation to coal seam gas projects in New South Wales. This gives farmers the right to refuse entry to Santos and AGL on their properties, and allows farmers to determine which types of operations occur on their land.

[75] NSW Chief Scientist & Engineer (2013)
[76] ABS (2013)

Public confidence undermined by lack of information

The rapid growth of the CSG industry has also led to public concerns about environmental and health impacts, with a particular concern over a lack of impartial, verifiable data used in the consultation process. This led to a public perception that the risk of CSG development is greater than claimed by the industry, and has been reinforced by a number of incidents. In New South Wales, several incidents together lowered the reputation of the industry, including the Eastern Star Pilliga incident in 2010, where Santos ultimately admitted liability for a number of spillages of salt water from a faulty water treatment plant,[77] and the AGL air quality breaches between 2009 and 2012, when AGL failed adequately to monitor emissions from a gas plant near Sydney,[78]

In addition, the fact that regional governments earn royalties (between 10 and 12%) and taxes from CSG has also created a belief that States have a conflict of interest and are therefore not able to weigh the risk of the development of CSG impartially. For example a report by the New South Wales Chief Scientist suggested that there is a widespread perception that industry and government are, at worst, colluding against the public's best interests.[79] To restore faith in the government process, in February 2013 the New South Wales Office of Coal Seam Gas was established and the Office of the Chief Scientist took responsibility for the objective scientific assessment of CSG. Furthermore National Farmers' Federation President, Jock Laurie was in December 2012 appointed the State's first Land and Water Commissioner to build confidence in the process governing exploration activities in NSW and to facilitate greater consultation between government, community and industry. However, this has yet to fully restore public confidence, not least because the media has been active in framing the CSG debate, with most reports being anti- rather than pro-CSG as it "makes a better story and garners more interest" (Taylor et al., 2013). Notably the number-one rated radio announcer in Sydney has been particularly vocal, and the debate has also been aroused by the film *Gaslands* (about shale gas in the US) with its evocative images of poor well construction that supposedly caused bubbling methane, foaming wells and the flaming water tap. In response industry stakeholders have complained that the media has often not presented the industry side of the story. As a result APPEA, the main national body representing Australia's oil and gas exploration and production industry, has developed a campaign entitled "Our natural advantage"[80] to counter claims by anti-gas groups and highlight the positive consequences of gas production. However, to date the impact on the public has been minimal and CSG developers continue to face significant opposition to their activities.

Regulatory burden is increasing

The level of public concern over the impact of CSG and other gas production activities has sparked a series of government regulations that also threatens to undermine the development of the industry. At a general level, APPEA states that Australia already has more than 150 statutes governing offshore and onshore upstream petroleum activities, regulated by more than 50 government agencies at a national, state and territory level, and it claims that the inefficient, duplicative and bureaucratic organisation of these institutions is putting the industry's expansion at risk.[81]

These sentiments were shared by the Chairman of BG Group Australia who stated that activists are currently determining public policy.[82] In New South Wales, for example, this has led to policy decisions such as exclusion zones for CSG production within 2km of residential land and sensitive

[77] Australian, 21 Sept 2013, "Santos to pay the price for CSG contamination"
[78] Sydney Morning Herald, 1 April 2013, "AGL failed in its duty to properly monitor emissions"
[79] NSW Chief Scientist & Engineer (2013)
[80] APPEA(Our natural advantage)
[81] http://www.openaustralia.org/debates/?id=2014-03-26.16.2
[82] McCullough (2013)

agricultural areas, and total exclusion of the industry from water resource areas (such as that between Sydney and Wollongong). This has caused AGL to reconsider its exploration and production plans, Dart and Metgasco to withdraw from New South Wales and Apex Energy to withdraw plans to drill in the water catchment between Wollongong and Sydney. As a result AGL alone has had to reduce the value of its gas reserves in New South Wales by $343 million as a consequence of the exclusion policy, with seventeen years of prospective gas supply in New South Wales now effectively ''sterilised'.'[83] Despite these problems, though, industry and government representatives continue to argue that CSG must come online to fulfill the contracted obligations for export sales and provide a back-up in case domestic gas is required to supplement supply to export. The dilemma in meeting the needs of the market and also the demands of the public and government over environmental issues is therefore very clear for the CSG industry.

Indeed the conflict of interest has been evident in the fact that public concern has caused a moratorium on fracking and the ban on the use of fracking chemicals in New South Wales and Victoria. In Victoria the Premier has extended a moratorium on hydraulic fracking despite the conclusions of a report from the Victoria Government-appointed Gas Market Task Force that recommend that it should be allowed. The Task Force will now undertake a further round of consultation before the Victoria Government makes a final decision on fracking, which has effectively delayed onshore gas production by approximately one year until at least mid-2015 (well after the 2014 Victoria state election).[84]

In June 2013, the Federal Government also got involved in the CSG debate and passed an amendment to Federal environmental law (Environment Protection and Biodiversity Conservation Amendment Act 2013 – EPBC Act), which now requires Federal approval for Coal Seam Gas developments that are likely to have a significant impact on water resources. This mechanism is called the “water trigger”, and means that an environmental impact assessment and approvals process is now required with the Federal as well as State Government for some CSG projects.[85] These amendments to the EPBC Act have caused additional costs for the CSG industry and the Mining Council of Australia has noted that the new requirements add additional approval hurdles and will add up to two years to the approval processes, which would cost an overall additional $360-$730 million.[86] A first example of the legislation in practice was seen in July 2013 when Apex Energy was refused permission under the EPBC Act for a drilling program for exploration in the Sydney Water Catchment area between Wollongong and Sydney.

In response to concerns about increased costs the Federal Government has made an attempt to reduce the burden of the assessment process. Representatives of the States, Territory and the Commonwealth met in mid-December 2013 at the Standing Council on Energy and Resources (SCER) and agreed to develop a national ‘harmonised’ environmental regulatory framework for the CSG industry. The framework aims to focus on water management and monitoring; hydraulic fracturing and chemical use; and well integrity and aquifer protection. The aim is to improve existing jurisdictional standards and practices, in order to build community confidence in the effectiveness of regulatory regimes governing the industry's development. However, until formal action is taken to reduce the approval burden the CSG industry will continue to face a significant regulatory process

[83] Robins B. (2013)
[84] APPEA (2013)
[85] http://www.environment.gov.au/topics/about-us/legislation/environment-protection-and-biodiversity-conservation-act-1999/what-5
[86] http://www.ncoa.gov.au/docs/submission-minerals-council-of-australia--attachment-1.pdf

and public opposition as it attempts to develop the gas reserves that are now needed to meet export and domestic demand.

6.5 The combined impact of CSG developments on Queensland's major LNG projects

The development of CSG in general, then, is not only an operational challenge but is clearly an emotive issue in Eastern Australia. It is also very obviously vital to the development of the three liquefaction projects that are being developed on the east coast, which when operating at plateau, will add an additional 25 mtpa of LNG capacity. These projects are all located close to each other on Gladstone Island in Northern Queensland, and are operated by three different consortia: Queensland Curtis LNG (QCLNG) is operated by a BG-led group, Asia-Pacific LNG (APLNG) by a ConocoPhilips/Origin consortium and Gladstone LNG (GLNG) by a Santos-led group. However, one key issue common to all these projects is gas supply, although each has its own variant on the possible outcomes. The project details are referred to in Table 4 above, but it is worth reiterating the major points here in order to underline the key issues.

Table 9: The major LNG projects on the east coast of Australia

Under Construction	Owners	Capacity (Mtpa)	LNG Trains	Cost (US$bn)	Completion Date
Australia Pacific LNG	ConocoPhilips (37.5%), Origin Energy (37.5%), Sinopec (25%)	9	2	22.5	2015/16
Queensland Curtis LNG	Train 1: BG Group (50%), CNOOC (50%); Train 2: BG Group (97.5%) Tokyo Gas (2.5%)	8.5	2	20.4	2014/15
Gladstone LNG	Santos (30%), PETRONAS (27.5%), Total (27.5%), KOGAS (15%)	7.8	2	18.5	2015
Planned					
Arrow LNG	Shell (50%), PetroChina (50%)	8	2	na	2017+
Fisherman's Landing	LNG Ltd (100%)	1.5 (3.0)	1 (2)	na	2017+

Source: Company Data

QCLNG (BG, CNOOC, Tokyo Gas), FID: October 2010

Queensland Curtis LNG is currently a 2-train scheme with a targeted capacity of 8.5mtpa, due to come online in the fourth quarter of 2014. As can be seen in Table 10 below the gas has been contracted to a variety of Asian buyers as well as to BG itself, and indeed BG's global gas portfolio does provide some flexibility in the supply and marketing of QCLNG gas. Nevertheless it is particularly important that the project comes online on schedule, as the operator BG has firmly committed to first LNG production this year. Gas supply is being sourced from CSG assets owned by Queensland Curtis Gas (QCG) which, according to the latest BREE report, has 10,500 Pj (280 Bcm,

9.9 Tcf) of 2P proven & probable reserves in the Surat Basin which will be supplied to QCLNG through a 340 km gas pipeline. QCG is currently drilling 2000 wells as part of the first phase of dedicated production for the project and is also carrying out an aggressive exploration program in the Bowen Basin to find reserves for a potential train 3. It has been reported that at the end of 2013 1,900 of the required wells had been drilled and that as of November 2013 70% of the overall project facilities were complete,[87] implying that Train 1 of the project is on schedule for first gas in Q4 2014. Train 2 is then expected to be online in the second half of 2015, with the overall project producing at full capacity by the first half of 2016.

However, although the initial drilling campaign appears to be on track and the 2P gas resources available would appear to be just adequate to meet 20 years of contracted supply (even allowing for some gas lost in transmission and LNG production), the QCLNG partners have still decided that they need to buy in gas from the domestic market, especially in the early years of the project. BG itself has acknowledged that the CSG development requires a complex and extended start-up process, with thousands of wells being tied into the overall system, and as noted above the individual well performance can be very variable and uncertain. As a result BG has announced that it will purchase 10-20% of the initial gas supply requirement from the domestic market in 2014-16, and has contracted to buy 7.6 Bcm from various suppliers over the next three years (see Table 11 below). All the purchased gas will come from the Surat Basin, and could of course also have been supplied into the domestic market.

Table 10: Gas sales contracts signed by Queensland LNG projects

	Buyer	Volume *mtpa*	Length *years*	Start
QCLNG	BG	3.7	20	2015
	CNOOC	3.6	20	2015
	TEPCO	1.2	20	2015
	Chubu Electric	0.4	20	2014
APLNG	Sinopec	7.6	20	2015
	Kansai Electric	1	20	2016
GLNG	Petronas	3.5	20	2015
	KOGAS	3.5	20	2015

Source: Company data

GLNG (Santos, Petronas, Total, Kogas), FID: January 2011

Gladstone LNG is a two-train 8 mtpa project that has contracted to sell its gas in large part to project sponsors Petronas and KOGAS (see Table 10 above). As of February 2014 GLNG was reported to be 75% complete,[88] with first gas being targeted from the first half of 2015, although the operator Santos has not been specific about a date as of mid-2014. However, the major problem for GLNG is a lack of an adequate reserves base, as it has dedicated 2P proved and probable reserves totaling only 5376 Pj (140 Bcm, 5.4 Tcf) of CSG located in the Surat Basin, 435 km from the LNG plant. Allowing

[87] http://www.bg-group.com/assets/files/cms/BG_Group_Q4_Analyst_Conference_Call_QA.pdf.pdf
[88] Energy Quest (2014),

for some gas losses in the transport and liquefaction processes this would provide only 11 years of production at peak capacity, well short of the 20-year contracts signed with the buyers. As a result, although the project seems to be on target to drill the 1000-1400 wells that will be needed at official start-up (see Table 12), and despite the fact that the total approved well count would allow the number to be increased to 2650 wells (with a further 4,100 wells awaiting approval), it is already clear that significant gas will need to be purchased from the domestic market if the LNG scheme is to operate at full capacity.

Table 11 outlines some of the plans that the GLNG partners have made to fill the gap in supply. In 2012 it was agreed that the project would purchase 365Pj (9.5 Bcm) of gas from Origin to act as ramp-up gas, and this was supplemented in December 2013 with a further agreement to buy an additional 100Pj (2.6 Bcm) in a five-year deal from 2016. Furthermore Santos will pipe a total of 750 Pj (130 MMScf/d) of gas from its Cooper Basin assets in South Australia, (South Australia CB JV: Santos 66.6%, Beach 20.2%, Origin 13.2% with an estimated 3 tcf gas reserves) through the 935 km Epic pipeline (Wallumbilla to Moomba), of which 51Pj, or 1.4 Bcm, should be available in 2015. However, despite all this additional gas Santos will still have an estimated shortfall of 2P reserves, based on 20 years LNG production at capacity, of approximately 100bcm. It does have some reserves in the New South Wales Gunnedah Basin that it could use, but even this would not cover the whole shortfall. Santos did try to secure some Beach Energy gas from the Cooper Basin, but was outbid by Origin who could sell the gas to the APLNG project (see comment below), and therefore may be forced to source more gas from its Cooper Basin assets, through higher production, if its partners agree. The LNG sales agreements for GLNG are understood to have a long LNG production ramp-up, which may provide some relief for Santos while it sources additional gas, but nevertheless the project still has clear gas supply issues that need to be resolved and this is likely to have a significant impact on the domestic market in Eastern Australia.

Table 11: Gas sourced from domestic market by QCLNG and GLNG

Project	Volume *bcm*	Seller	Comment
QCLNG	0.78	Origin	Deal over two years signed in Nov 2013
	4.94	APLNG	Extra gas during 2015-16 ramp up
	1.92	AGL	3 year supply from 2014
GLNG	9.48	Origin	May 2012 deal for ramp-up gas
	2.60	Origin	Dec 2013 - 5 year deal from 2016
	1.36	Santos	3rd party gas in 2015
APLNG	3.75	Beach	8-year deal signed in 2013

Source: EnergyQuest (2014)

Asia Pacific – AP LNG (ConocoPhillips, Origin, Sinopec), FID: Train 1 July 2011 & Train 2 July 2012

AP LNG is also a two-train project with a total capacity of 9mtpa, with the LNG having been largely contracted to one of the partners, Sinopec, but also to Kansai Electric in Japan. As can be seen from Table 12 the project is making good progress towards drilling the 1100 wells that are required for initial start-up, and APLNG is also the best positioned of the three Queensland LNG projects when it comes to available CSG gas reserves. It has over 13,000 PJ (350 Bcm, 13 Tcf) of 2P proven & probable CSG reserves dedicated to the project, which would increase to 16,000Pj (420bcm, 16 Tcf)

if 3P probable reserves are also included. However, even though these reserves would be sufficient to cover around 25 years of LNG output, even allowing for losses, the project partners also have access to conventional gas production. In April 2013, Origin bid and won a contract to purchase 140 Pj (3.75 Bcm) of gas over 8 years (17 PJ or 0.5 Bcm/year) of Beach Energy's equity production from the South Australia Cooper Basin (see Table 11 above), which had previously been targeted at the New South Wales market but which could now, at Origin's discretion, be available for APLNG. Extra reserves could also come from Arrow Energy, because Shell has decided to defer the development of its Arrow LNG project at Gladstone. It is therefore possible that Arrow could join the AP LNG scheme, bringing with it sufficient reserves to produce 270 Pj/annum (7 Bcma or 670 MMcsfd) of gas, which would be enough to supply one train. This could potentially imply a third train at AP LNG,[89] or alternatively the extra gas could supply trains 1 & 2 but still provide small volumes for train 3, although it should be noted that Shell has not made any firm commitment to this idea and remains in negotiation with other LNG projects in the region.

Table 12: Progress with gas development for Queensland LNG projects

Project	Wells needed for 2 trains	Q2 2013	Q3 2013	Q4 2013	Total wells since FID at y/e 2013	% of total required
QCLNG	2000	196	225	205	1900	95%
APLNG	1100	87	105	108	610	55%
GLNG	1000-1400	56	67	38	398	28%
Arrow	2500	0	0	0	0	0%

Source: Companies, Department of Natural Resources and Mines, Australia

It is clear, therefore, that although it was initially assumed that the three Queensland projects would have their own equity gas as feedstock for their liquefaction plants (based on CSG), it now appears that at least two of the plants will be short of some gas, with the result that they will need to source gas from the domestic market. Even one of the main APLNG partners, Origin Energy, has contracted gas originally intended for the domestic market as an insurance policy, although its LNG project appears to have sufficient reserves of its own. The key driver for these purchases of domestic gas, apart from concerns about overall levels of reserves and well drilling, has been nervousness about the deliverability of gas from CSG wells with uncertain initial production and forward decline curves. This has led LNG project sponsors to contract for domestic gas supply to cover the ramp-up period for their projects (the first 3-4 years), and this has had the direct consequence of altering the dynamics of sales to domestic consumers, as reflected in the market analyses for each State described above. This helps to explain the anticipated dip in domestic gas consumption in the 2014-18 period, especially in the power sector, as gas is diverted to LNG projects. In the longer term the potential availability of existing reserves and future resources should ensure that a more balanced supply-demand picture can be re-established once well performance at the CSG assets has been established, but until then the price of gas in the domestic market, and the reaction of domestic consumers and politicians to the export projects, is likely to be volatile. The next section analyses this situation in more detail.

An alternative option available to LNG project investors is to procure short-term cargoes either from within their own portfolios or from the LNG spot market. This was the case for the delayed Tangguh project in Indonesia in the 2000s. However, with recent Asian spot cargo prices in the $12 to

[89] Note: In September 2011 Arrow acquired Bow Energy which had 240 Pj (2.4 tcf) of 2P CSG reserves and 2752 (27 tcf) of 3P CSG reserves in Queensland's Surat Basin.

$20/MMbtu range this serves to indicate a) that recourse to the Australian domestic market is generally preferable and b) in extremis these projects could afford to take domestic prices up to the lower of Asian LNG spot prices or LNG contract prices (both on a net-back basis) depending on the tightness of supply/demand balance in the domestic market.

6.6 Gas contracts and prices in Eastern Australia

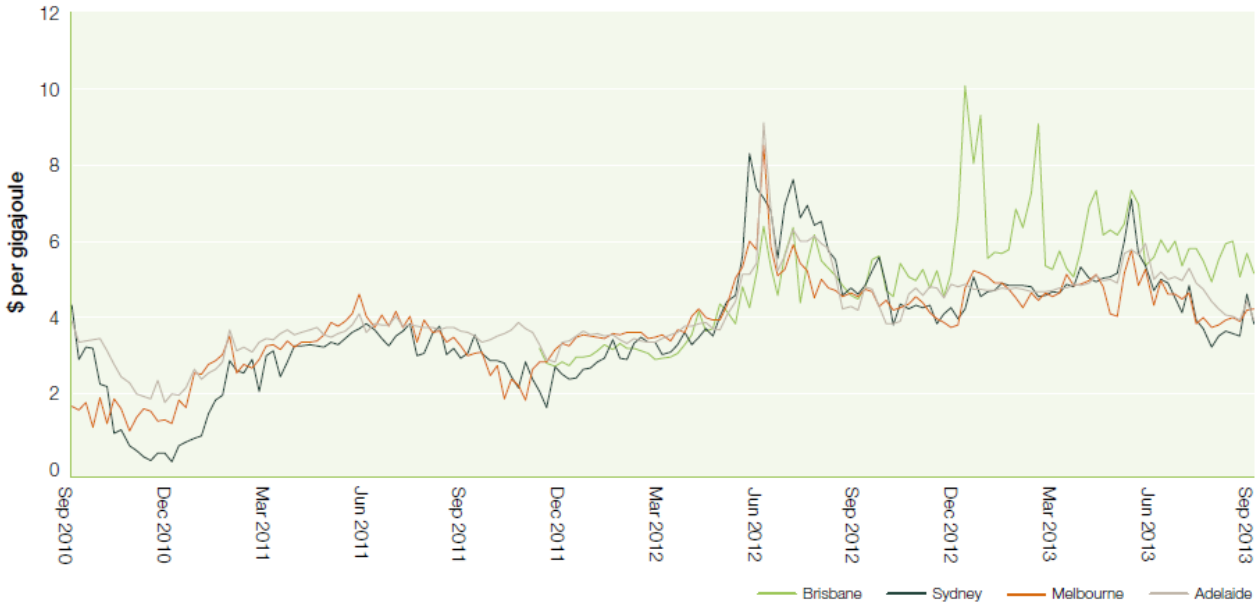
As has been mentioned above, gas prices have historically been set within the context of long term gas supply agreements (GSAs) between producers and consumers on the east coast, with the actual price levels being a matter of confidential negotiation and so not transparent. However, the remote nature of the market, without an export option, and the fact that in the power sector gas had to compete with relatively low cost coal as an alternative fuel, have meant that prices to date have been relatively low by international standards. Indeed this has become more obvious over the past few years due to the establishment of trading exchanges in the key States in the region. In June 2010 the AEMO set up a Short Term Trading Market (STTM) in New South Wales, South Australia, and Queensland, with gas trading hubs at Sydney, Adelaide and Brisbane respectively. [90] Victoria, however, has a separate market with a different design but the same overall goal of providing a spot market clearing price.[91]

Recent prices in the STTM and Victorian markets are shown in Figure 22 below, and indicate that there has been a significant move up over the past four years. The gas price in Sydney reached a low of below A$1/GJ (US$ 0.85/MMBtu) in December 2010 but had reached A$4/GJ (US$3.40/MMBtu) by September 2013, having peaked at a level of over A$8/GJ (US$6.80/MMBtu) in mid-2012. In a similar trend, the Brisbane price has moved from A$2/GJ (US$1.70/MMBtu) in 2010 to a peak of A$10/GJ (US$8.50/MMBtu) in late 2012 before settling at around A$6/GJ (US$5.10/MMBtu) in 2013. Indeed the average for all the East Australia markets in 2013 has been in the range A$4-6/GJ (US$3.40-5.10/MMBtu), two to three times the level seen in 2010.

[90] Gas is traded ex ante (a day ahead) with AEMO setting a day-ahead price and providing a market schedule. As demand predictions become more accurate, shippers can rebid by re-nominating quantities of gas with pipeline operators. Real-time information on the state of the market, pipeline capacities, production capability, pipeline storage, and demand forecasts is provided by the Gas Bulletin Board. The physical balancing of gas is the responsibility of pipeline operators. Some shippers can provide balancing gas to supplement shortages, which is purchased by AEMO as a part of Market Operator Services.

[91] Bids are stacked and the spot market clearing price is set at the required demand. Gas prices set in the market are effectively in an unlimited range from A$0/GJ to A$800/GJ (US$0-680/MMbtu). Bidding commences at 6am each day, with rebidding at 10am, 2pm, 6pm and 10pm, and prices are gas-only and do not include transmission price. As with the other markets, AEMO is responsible for the physical balancing of gas and the financial market (Note: in the STTM pipeline operators are responsible for balancing).

Figure 22: Gas prices in Eastern Australia



Source: AER (2013a)

The sharp increase in prices on the east coast, in particular since 2012, has reflected the increasing availability of export markets as an option for producers, in particular because at least two of the LNG projects under construction have contracted for gas that might otherwise have been destined for the domestic market. Clearly the question of gas diversion is not black and white, as some third-party gas purchased by the LNG operators would not have been produced if it had not been for this extra demand and the availability of higher prices. Nevertheless the experiences of major industrial customers on the east coast suggest that it is becoming more difficult to contract for long-term gas at low prices a) because producers are now considering a greater variety of sales options and have consequently got greater bargaining power and b) because in all likelihood the increased underlying cost-base of the new gas production renders the historical lower contract prices unrealistic.

Table 13 shows a selection of contracts that have been signed in late 2013 and early 2014, emphasizing that producers now have a clear choice between selling to LNG export projects or domestic consumers. The details of the price arrangements can only be gleaned from various reporting sources, but a series of statements would suggest that the level of prices is significantly higher than the spot price seen at the various hubs. In December 2013, for example, Santos reported that it had signed five domestic contracts at prices over A$8/GJ (US$7.20/MMBtu), while in the same month Incitec announced a gas purchase agreement with AGL for its Phosphate Hill plant that implied a delivered gas price of A$11-12/GJ (US$9.80-10.80/MMBtu). At the other end of the scale Strike Energy announced the signing of a deal with Orora in January 2014 with prices in the range A$6-8/GJ (US$5.40-71.0/MMBtu), while in a recent report the advisory company IES estimated prices of A$7-9.00/GJ (US$6.25-8.00/MMBtu)for a number of recent agreements.[92]

[92] Energy Quest (2014)

Table 13: Some recent gas contracts in Eastern Australia

Announced	Seller	Buyer	Volume	Commences	Term
			bcm	*year*	*years*
LNG					
Oct-10	Santos	GLNG	19.5	2014	15
May-12	Origin	GLNG	9.5	2015	10
Nov-13	Origin	QGC	0.8	2014	2
Dec-13	Origin	GLNG	5.0	2016	5
Total			*34.8*		
Domestic					
May-11	AGL	Xstrata	3.6	May-13	10.5
Dec-12	Origin	MMG	0.6	2013	7
Apr-13	Beach	Origin	4.5	2014-145	08-Oct
May-13	Esso-BHP	Lumo Energy	0.6	2015	3
Jul-13	Strike Energy	Orica	3.9		20
Sep-13	Esso-BHP	Origin	11.2	2014	9
Nov-13	Esso-BHP	Orica	1.1	2017	3
Dec-13	AGL	Incitec	0.5	2015	2
Jan-14	Strike Energy	Orora	0.8	2017	10
Feb-14	Strike Energy	Austral Bricks	0.3	2017	10
Total			*27.1*		

Source: Energy Quest (2014)

Prices for the gas sales to the LNG plants appear to have been set at levels similar to those for the domestic market. In May 2012 Origin contracted to sell gas to GLNG at $8.00/GJ (US$7.20/MMBtu), while the deal struck in December was priced in an estimated range of approximately A$10.00/GJ (US$8.90/MMBtu). Interestingly both deals were to provide gas at Wallumbilla,[93] a gas trading exchange in Queensland that was established in March 2014 and whose location makes it ideally placed to act as the gas supply point for gas supplied to LNG export projects because of its proximity to them and the main domestic supply routes. This hub is expected to attract short-term traders, which will deepen market liquidity, and make spot and forward prices available to increase trade. It is also likely to encourage an increasing trend towards gas being priced on an LNG netback basis as the domestic and export markets become linked.

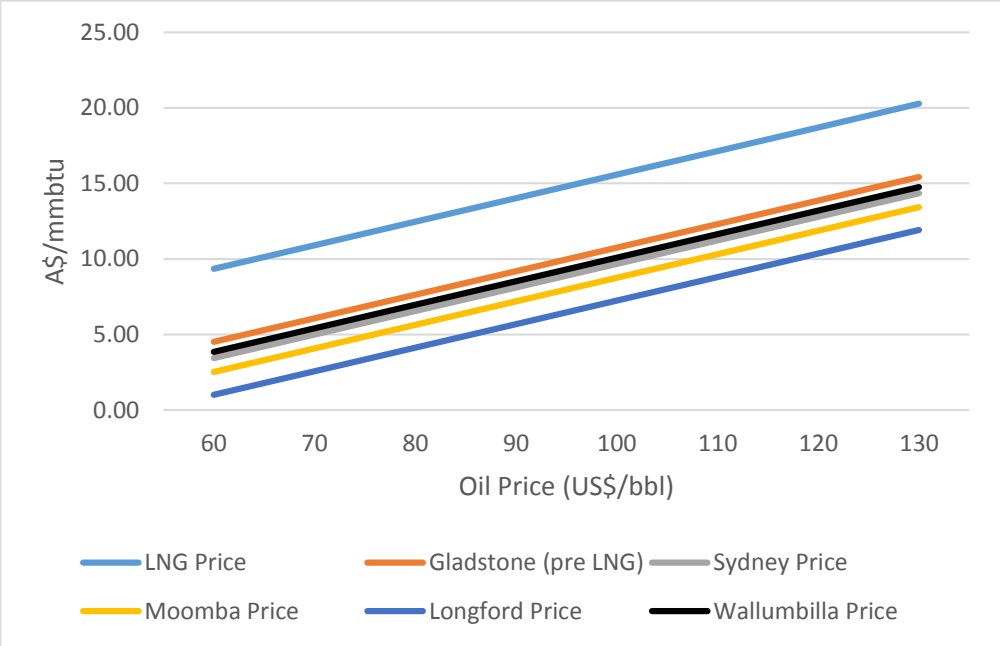
Figure 23 shows a calculation of the netback price of LNG based on an oil-linked contract and a 14.5% slope, with an exchange rate of A$1=US$0.93. At a US$100/bbl oil price the LNG price delivered to Japan would be US$14.50/MMbtu,[94] equivalent to US$13.50/MMbtu at Gladstone after removing shipping costs. The cost of liquefaction is assumed to be US$3.50/MMbtu, bringing the netback price at Gladstone down to US$10.00/MMbtu, or A$10.75/MMbtu. The removal of transport costs to various points in Eastern Australia then provides netback prices either at pricing hubs such as Wallumbilla or Sydney or at production points such as Moomba. The estimated netback price at Wallumbilla, for example, would be A$10.10/MMbtu or A$9.60/GJ, close to the prices agreed in recent

[93] http://www.originenergy.com.au/news/article/asxmedia-releases/1539

[94] Internationally traded LNG is priced in US$/MMBtu. These prices have been converted to A$ in Figure 23 to compare with local prices

contracts discussed above. The price in Sydney would be A$9.20/GJ, again within the range of recent industrial prices in Eastern Australia. The conclusion therefore must be that the Eastern Australian market is adjusting to a new interaction with the global LNG market and customers will therefore have to pay higher prices in future.

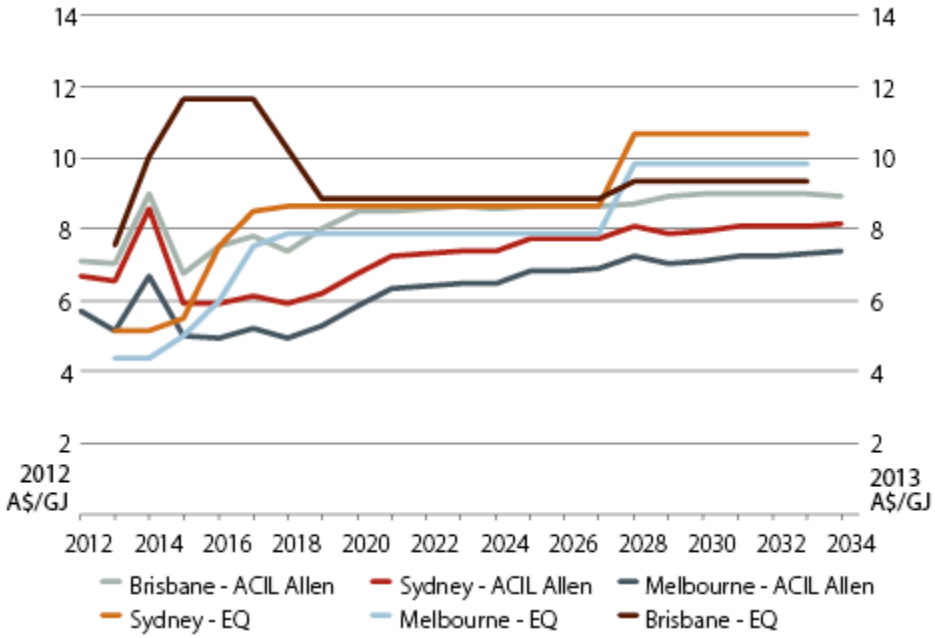
Figure 23: Netback price of LNG to various locations in Eastern Australia



Source: Authors' estimates

Indeed this new reality has over the past few months been reflected in the forecasts of a number of agencies and consultancies who foresee a significant rise in gas prices in Eastern Australia over the next decade, as shown in Figure 24. Not surprisingly, though, these increases have provoked a political debate about whether Australia should allow its gas to leave the country in such large amounts or be held back for domestic consumers at lower prices.

Figure 24: Gas price forecasts for Eastern Australia



Source: BREE, (2013a)

The greatest impact could well be felt in the State most reliant on gas imports - New South Wales. BREE predicts that prices in the State will increase as the domestic and export markets become increasingly linked and as the cost of domestic production rises ,[95] citing estimates from consultancy ACIL Allen which indicate that prices could rise from approximately A$6.50/GJ (US$5.80/MMBtu) in 2013 to approximately A$7.50/GJ (US$6.70/MMBtu) in 2028, while EnergyQuest predicts that prices will rise from approximately A$5/GJ (US$4.50/MMBtu) in 2013 to approximately A$10.50/GJ (US$8.93/MMBtu) in 2028.[96] Meanwhile gas marketers AGL and Origin Energy have already applied to the Independent Pricing and Regulatory Tribunal (IPART), the setter of retail prices in New South Wales, for a 20% increase in retail prices in New South Wales from July 2014[97].

The impact of these expected gas price rises, in combination with possible gas shortages, would of course be to put pressure on both households and industry, and is already having a political backlash. The Federal Minister for Energy has stated that "hundreds, if not thousands" of jobs would be at risk with low gas supply and high prices in New South Wales. Furthermore industry lobby group Manufacturing Australia has stated that local manufacturers simply cannot secure long term contracts for gas, saying that "what gas is available is skyrocketing in price by up to 200 per cent. Left unchecked this crisis will permanently push many manufacturing businesses over the edge, costing Australia 200,000 manufacturing-reliant jobs and $28 billion in economic value."[98] Michael Fraser, CEO of AGL and Grant King, CEO of Origin Energy have also commented that the tightening of gas markets will lead to destruction of demand, particularly in gas-fired electricity generation.[99]

[95] BREE (2013a)
[96] EnergyQuest (2013)
[97] Dingle, S. (2014)
[98] http://www.abc.net.au/news/2013-09-30/gas-shortages-nsw-macfarlane/4980952
[99] The Australian, 3 Aug 2013, “AGL warns of plant closures as carbon price falls and gas prices rise”

One solution to increase the supply of gas in New South Wales could be the development of CSG within the state but, as discussed previously, public sentiment is against such a move and the State Government has introduced legislation that prevents CSG development within 2km exclusion zones from areas with sensitive land use. The State of Victoria is adopting a similarly aggressive tone towards the development of CSG reserves, despite the fact that its historic conventional reserves now seem to be in decline, with the regulator AEMO forecasting shortages of gas as soon as 2027.[100] Despite this outlook the Victorian government has instituted a moratorium on fracking and halted the award of new coal seam gas exploration licences. In November 2013 a government-appointed Gas Market Taskforce suggested that the moratorium should be lifted in order to encourage the development of CSG to increase gas supply (and by implication to reduce gas prices), but this advice was rejected and the ban was extended to July 2015. Indeed the Premier of Victoria, Dr Napthine has since stated that "we will never, ever allow onshore gas if it jeopardises our underground water, if it jeopardises our environment, and if it jeopardises our food and agriculture production."[101] However, the result of this strategy is that Victoria is projected to experience an increase in the price of gas, with EnergyQuest predicting that the wholesale price in Melbourne will increase from less than $4.20/GJ (US$3.75/MMBtu) at present to almost A$10/GJ (US$8.90/MMBtu) in 2028, while ACIL Allen projects that prices will increase from A$4.50/GJ (US$4.00/MMBtu) to approximately A$7.50/GJ (US$6.70/MMBtu) on the same timescale.[102]

6.7 Could a gas reservation policy be introduced?

The potential shortages of gas and the price rises that are anticipated in Eastern Australia have led some commentators to describe the situation as an energy crisis, and have also led to calls for a domestic gas reservation policy, as has been implemented in Western Australia. However, as has been seen in the western region, implementation of such a policy is fraught with economic and legislative difficulty. Indeed in its 2012 Gas Market Report, BREE said: "In the short term, a reservation policy diverts gas from the export market to the domestic market, increasing domestic supply and placing downward pressure on domestic gas prices. However, in the long term it may work as a disincentive for industry to develop further gas supply projects." The clear implication is that although gas reservation may have a short-term political benefit, in the long term it will not provide a solution to gas shortages or lower gas prices.

Interestingly there is one state in the eastern market that does have a type of reservation policy. The Prospective Gas Production Land Reserve (PGPLR) policy was introduced in Queensland in 2011 and allows the Government to determine that gas produced in a leasing area can only be sold within the Australian domestic market. To ensure the viability of the policy, the PGPLR only applies to new tenders if the Government's annual Gas Market Review process identifies domestic supply constraints. This aims to prevent the LNG export industry creating a gas shortage for large users such as fertiliser producers, mineral processors and electricity generators[103]. However, in 2013 the Queensland Energy Minister said that he would "not move to gas reservation… unless everything falls by the wayside".[104] Furthermore it is unclear whether the policy would be implemented to benefit other States in the region (in particular NSW) if producers in Queensland were keen to export their gas rather than sell it domestically. It is possible that the Federal government could insist on inter-State trade as Section 92 of the Australian Constitution prohibits action by either the Commonwealth

[100] AEMO 2013a
[101] Cook, H. (2013)
[102] BREE (2013a)
[103] Queensland Legislation (2011).
[104] MacDonald-Smith, A., (2013b)

or a State that discriminates against interstate trade or protecting a State against competition from other States. However, the former Federal Government's 2012 Energy White Paper did not support reservation policies or subsidies that maintain separation between domestic and international gas markets. It suggested that open trading arrangements and higher prices should drive development, additional supply and timely market response. The current Federal Minister for Industry and the opposition leader have both indicated that domestic gas reservation would not be considered for existing projects, although they have not ruled it out for new projects.[105]

Nevertheless, the debate continues between the various vested interests, with the Business Council of Australia, and Manufacturing Australia on one side being extremely concerned about the impact of LNG export on prices, gas availability and the subsequent impact on business. They are calling for domestic gas reservation, licensed acreage to be put aside for domestic supply, a differentiated gas price for export and domestic users, and/or an obligation on gas producers to offer supplies domestically.[106] On the other side of the argument, the gas producers are unsurprisingly opposed to domestic gas reservation: Origin Energy, Santos and AGL have warned that reserving gas would cost A$6billion (US$5.4 billion.) in foregone gross domestic product and that "talk of reserving Australia's gas for domestic will keep it in the ground".[107] Meanwhile APPEA, a consortium of gas production companies, suggests that the key to driving down costs for all consumers is to continue to develop resources and facilitate access to export markets.

In an additional twist, a number of groups including the New South Wales Farmers Federation, Manufacturing Australia and Dow are petitioning for a "National Interest Test" for gas export. This would be similar to US policy where the export of gas to non-Free Trade Agreement countries is subject to a National Interest Test. However, the Grattan Institute suggested "there is little to be practically gained from imposing 'public interest' or 'national interest' tests for LNG export projects. Rather, such tests have the potential to impose a regulatory burden on developers and provide a platform for future lobbying by user groups." [108] This sentiment was further reflected at a recent New South Wales Gas Summit organised by the former Minister for Resources, Energy and Tourism who stated in response to talk about a National Interest Test that "the last thing we need is another hurdle".[109]

A further example of state reluctance to countenance any sales restrictions on producers was provided by the South Australia Resources Minister, who has indicated that South Australia will not prioritise gas to domestic markets over LNG, specifically stating that contracts for supply to LNG export will not be changed to divert gas to New South Wales "because of a crisis created by a lack of political leadership."[110] As a result, although the debate is likely to continue as gas prices rise and gas availability becomes more contentious, the practical implementation of a gas reservation policy or any export restrictions is unlikely. Indeed although Ian McFarlane, Minister for Industry in the current (2014) coalition federal government, has stated his commitment to find a solution to the potential gas supply crisis in eastern Australia, his attention appears to be more focused on encouraging upstream investment by streamlining the approvals process for offshore developments (over which it has control) and trying to improve the process to streamline gas development assessment and create a one-stop-shop for environmental approvals for CSG.[111]

[105] Chambers, M., (2013b)
[106] Drummond, M., and Macdonald-Smith, A., (2013)
[107] http://www.afr.com/p/australia2-0/bca_seeks_deal_on_domestic_gas_supply_pJpoktttbf43Ev2MkyLZSJ
[108] Wood, T., Carter, L., (2013)
[109] http://minister.innovation.gov.au/ministers/macfarlane/transcripts/media-conference-nsw-energy-security-summit
[110] Macdonald-Smith, A., (2013b)
[111] http://www.ianmacfarlanemp.com/index.php?option=com_content&view=article&id=69:test&catid=2:speeches&Itemid=3

6.8 Conclusion – East Australia's gas debate and LNG projects

The East Australian gas market has been transformed from a purely domestic interaction between local suppliers and customers, albeit across five states, into a more globally-focused business by the imminent completion of three new LNG export projects at Gladstone. This situation has been further complicated by the fact that these projects are based on CSG reserves, the development of which is still rather uncertain. While the reserves in place appear to be sufficient, or very nearly so, on an overall basis, individual projects (especially Gladstone LNG) currently lack the resources to meet their export contracts and are therefore contracting for gas that might otherwise have gone to domestic customers. Meanwhile uncertainty over the deliverability of supply in the initial stages of CSG development at QCLNG has also led that project to contract for significant amounts of third party supply, again increasing pressure on the domestic market.

The overall result has been that the price of gas in all the states across the region has risen sharply over the past two to four years, and gas has become less readily available under long-term contracts. This has led both to demand expectations being reduced (especially in the power sector) and to industrial (and to an extent residential and commercial) customers having to pay prices that are now approaching export netback levels. This has caused some consumer lobby groups to call for a gas reservation policy, or some similar review of exports, to be introduced in order to make gas available and keep prices down. However, it would appear at present that any such move would not only be met with skepticism by regional politicians but could also be very hard to implement due to potential conflicts between federal and state law.

As a result, there would appear to be no threat to the progress of the projects that are currently under construction, and the progress being made at QCLNG, APLNG and GLNG would suggest that they will come onstream in the period 2014-2016 as planned, leading to a total of 25mtpa of new LNG export capacity being added to Australia's LNG industry, though capacity utilisation may be lower should gas supply be restricted. A more difficult question concerns the potential expansion plans for the three plants and also the prospects for other new projects in the region, in particular Arrow LNG and Fisherman's Landing LNG.

Given the supply issues that the project is already experiencing, it would seem unlikely that GLNG will be initiating expansion in the near future, while BG has also hinted that QCLNG is unlikely to add a third train until new gas resources have been proved up.[112] APLNG is best placed as far as gas reserves are concerned, but its expansion plans may now involve a tie-up with the Arrow LNG project, which has currently been delayed and is considering options to reduce its cost base. One of these could be to link up with APLNG in order to optimize the potential synergy benefits of having both projects at one site.[113] As far as Fisherman's Landing is concerned, although the project sponsors remain keen to progress the project a lack of available gas supply is a significant issue.[114] The project has no equity reserves of its own and, as discussed above, gas availability from third parties is becoming a problem for domestic customers and export projects alike. As a result, it may be some time before any firm commitment can be made on this new plant.

Overall, then, the most likely expansion beyond the three currently planned LNG projects is the addition of a third train at APLNG in co-operation with the Arrow LNG partners. Beyond that initiative, the development of the domestic and export markets in Eastern Australia will largely be determined

[112] http://www.theaustralian.com.au/business/mining-energy/bg-plans-for-lng-growth-on-hold/story-e6frg9df-1226819022669#mm-premium
[113] Chambers M (2014)
[114] http://www.abc.net.au/news/2014-03-07/fishermans-landing-lng-plant-plans-hits-hurdle/5305534

by the reaction of producers to the continuing increase in prices in the region. It is possible that supply, both conventional and unconventional, could be encouraged by a domestic price that is likely to reach netback parity in the near future, meaning that producers no longer have an incentive to export gas. In this case the forecasts of gas shortages may be too pessimistic and domestic supply and demand may find a balance, especially in the power sector, which allows a more rapid recovery in consumption once the ramp-up period at the three CSG LNG projects is complete.

7. The Future – the competitiveness of Australian LNG

7.1 Introduction

The initial conclusions from the analysis of the Western, Northern and Eastern markets above, and the LNG projects currently under construction within them, is that although they have suffered from cost overruns and delays and are also causing a significant re-assessment off the domestic gas price environment, it is nevertheless highly likely that Australia will have 62mtpa of extra LNG capacity from seven new schemes by 2018/19. Indeed the contractual obligations undertaken by the projects suggest that this must be the case. However, there are a further 20 projects with a total capacity of 78mtpa that are under consideration (see table 14 below), suggesting the possibility that Australia could expand its soon-to-be-achieved position as the world's largest LNG producer dramatically beyond 2020. Clearly the question of the economic viability of this additional new capacity is in question because of the high cost of the current projects, and it is also of course likely that, should a large number of the new projects proceed, the same capacity constraints could undermine development budgets and timetables once more. However, the one major difference with this future tranche of projects is that over 60% of the proposed volume is from brownfield expansion of existing projects while 24% is potentially from floating liquefaction (FLNG), and only 15% being greenfield land-based projects.

The prevalence of brownfield projects is not unexpected as project sponsors generally seek to improve their economic returns through increasing liquefaction plant capacity by constructing additional LNG trains. Brownfield expansions usually cost about 60-70% of equivalent greenfield projects as adding new trains to existing plant enables the project to take advantage of already developed infrastructure, leading to cost savings from reduced site preparation, use of existing storage tanks, the existence of established jetty and berthing facilities and sharing existing utilities (power, water and other infrastructure). As we discuss below, this means that brownfield expansions, even in a high cost environment such as Australia, can be very competitive in the global gas market compared with other new LNG supply sources.

Table 14: LNG projects under consideration in Australia (June 2014)

State	Project Name	Company's stated start date (if known)	Type of project	Capacity	Shareholders	Comments	Gas Source
				mtpa			
WA & Queensland	Debottlenecking of existing plants that are under-construction		Brownfield	5.0	Various	It is potentially possible to achieve additional LNG production, once a plant has been operational for a period.	Various
WA	Bonaparte FLNG	2019	FLNG	2.4	GDF Suez: 60%; Santos: 40%	FEED planned in Q1/2014 with FOD in mid 2015	Petrel, Tern & Frigate gas fields
WA	Browse (Floating)		FLNG	4.0	Woodside, Shell, BP, PetroChina, Mitsui & Mitsubishi	Using Shell's FLNG technology and Woodside's offshore development expertise for the basis of design. Broowse is expected to comprise of 2-3 FLNG facilities, each 3.6 mtpa.	Torosa, Calliance & Brecknock fields
WA	Gorgon Trains 4 & 5	2018	Brownfield	5.0	Chevron: 47.3%; Shell: 25%; ExxonMobil: 25%; Osaka Gas: 1.375%; Tokyo Gas: 1.00%; Chubu Electric: 0.417%	Additional liquefaction trains built on the Gorgon exisiting LNG project site	Gorgon, Chrysaor, Dionysus, West Tryal Rocks, Spar & Ansz-lo, 130km offshore NW Australia
WA	Maple LNG	2019	FLNG	1.7	PTTEP	Onshore and FLNG options being considered	Offshore in Timor Sea, Cash Maple gas fields
WA	Pilbara/Scarborough	-	Greenfield land based facility or FLNG	7.0	ExxonMobil/BHP	Gas has a low CO2 content Gas could be divefrted to Pluto LNG and developed as a brownfield expansion project	Scarborough & Jupiter gas fields, 280km south-west of Onslow
WA	Pluto Trains 2 & 3		Brownfield	8.6	Woodside: 90%; Tokyo Gas: 5%; Kansai Electric: 5%	Expansion project. To date, Sufficient gas reserves have not been formed to secure development of the project.	Pluto & Xena
WA	Sunrise		Greenfield land based facility or FLNG	3.5	Shell: 26.56%; ConocoPhillips: 30%; Osaka Gas: 10%; Woodside: 33.44%	International companies keen to develop as a FLNG project, but Timor Leste (which shares the gas resource in the Timor Sea which lies between Australia and Timor-Leste is subject to overlapping territorial claims by Australia and Timor-Leste.) seeks the LNG plant to be based on land in Timor Leste	Evans Shoal, Loxton Shoals, Sunrise & Troubadour
WA	Wheatstone Trains 3 & 4		Brownfield	9.0	Chevron: 64.14%; Apache: 13%; Kufpec: 7.0%; PEW: 8%; Shell: 6.4%; Kyushu Electric: 1.464%	Chevron has said that if additional drilling find more gas the in could supports an expansion of the Wheatstone LNG project.	Wheatstone, Lago, Julimar & Brunello
Queensland	Arrow LNG Trains 1 & 2		Greenfield	8.0	Formally Shell Australia LNG project	470 km pipeline from Arrow's CSG fields around Dalby and Surat Basin Could be developed as an expansion train at APLNG	Surat Basin
Queensland	Asia Pacific LNG (CP/Origin) T3		Brownfield	4.5	ConocoPhillips: 37.5%; Origin Energy: 37.5%; Sinopec: 25% (Trains 1 & 2 shareholding)	ConocoPhillips are considering a third train. There is a possibility that this could be developed by Arrow LNG	Surat & Bowen Basins
Queensland	Beach		Greenfield	1.0	Beach Energy, Itochu Corporation	Gas from Cooper Basin and Victorian gasfields	
Queensland	Curtis (BG) Trains 3 & 4	2018	Brownfield	8.6	BG	The signing of an agreement with CNOOC in May 2013 signalled a wider partnership and the possibilty of an expansion of the existing project once operational. Current plans are for EPC award in 2014 following a competitive FEED process with two companies	Surat & Bowen Basins
Queensland	Gladstone LNG (LNG Ltd) & Fishermans Landing	-	Greenfield	1.5	LNG Limited/Arrow	This project has been under discussion for some time. Could be expanded to 3 mtpa	Fishermans Landing, Gladstone
Queensland	GLNG (Santos/Petronas)		Brownfield	4.0	Santos: 30%; Petronas: 27.5%; Total: 27.75%; Kogas: 15% (Train 1 & 2 shareholding)	GLNG would be expected to consider an additional train once the first two trains are operational if sufficient gas is available	Surat & Bowen Basins
Queensland	Southern Cross (Impel)		Greenfield	0.7	Impel	Open access (could be expanded to 1.3 mtpa) 400 km pipeline is stated to be part of the project	Curtis Island, Gladstone
NT	Darwin Expansion		Brownfield	3.6	ConocoPhillips: 56.72%; ENI: 12.04%; Santos: 10.64%; INPEX: 10.52%; Tokyo Electric/Tokyo Gas: 10.08% (Train 1 shareholding)	ConocoPhillips is examining the possibility of expanding Darwin LNG, but it depends on finding the gas resource.	Bayu-Undan, Caldita, Greater Sunrise, Abadi & Evans Shoal
NSW	Eastern Star/Newxastle		Greenfield	0.5	Eastern Star Gas, Hitachi, Toyo	Newcastle Port Could be expanded to 2 mtpa	Use gas from Eastern Star's Narrabri coal seam gas project
				78.6			
Other							
WA	Browse Trains 1, 2 & 3 (Land)	Cancelled	Greenfield	12.0	Woodside, Shell, BP, PetroChina, Mitsui & Mitsubishi	Land based option at James Price Point was cancelled in 2013 as the potential costs would have been at least $80 bn.	Torosa, Calliance & Brecknock fields
Queensland	Sun LNG	Cancelled	Greenfield	0.5-1.0	Sojitz Corporation		Fishermans Landing, Gladstone

Key:
Expansion projects
Potential FLNG

Brownfield	**48.3**	61%
Potential FLNG	**18.6**	24%
Greenfield	**11.7**	15%

WA LNG Markets	**26.2**	33%
Eastern Market	**28.8**	37%
Floating	**18.6**	24%
Debottlenecking	**5.0**	6%

Source: David Ledesma research and analysis

7.2 Australian LNG will need to be cost competitive under new contractual terms

A major challenge facing new Australian LNG projects is that the pricing environment which they are likely to face in Asian markets is changing[115]. Most of the LNG offtake from the projects under construction in Australia was contracted before the concept of US LNG exports was considered to be a commercial likelihood, with the implication that LNG could now be priced on the basis of Henry Hub gas. LNG from the Australian projects under construction was contracted on oil-related pricing formulas, with slopes in the traditional 14-15.5% range, with oil price floors included in some contracts in a range of $40-60/bbl and ceilings of 80-110/bbl. Most of the newer contracts include some form of price review, to ensure that neither the buyer nor seller are stuck in a long-term contract that is out of the market, and this does create some risk even for the projects under construction, as they could face a price renegotiation if Henry Hub prices remain low and the current oil-linked contracts are therefore an excessive burden for consumers. More likely, though, is that any new projects will have to adapt to a lower price environment and will need to be competitive with US LNG exports, based on some assumption of Henry Hub prices. In November 2013 BG signed a wide-ranging agreement with Chinese company CNOOC that included a sale of 5 mtpa of LNG for 20 years beginning in 2015, sourced from the Group's global portfolio. It is understood by the authors that this LNG sale is priced on a hybrid US Henry Hub/oil-related basis. As some of this LNG is likely to come from QCLNG, it can be deduced that some LNG sales from Gladstone will likely be on a hub-related pricing basis. The pressure for other sellers to adopt this, or similar model, and therefore for specific projects to accept a lower price, is likely to increase if they are to be competitive in a global gas market with increasing supply options, with the alternative that surplus volumes will need to be sold on the spot market, giving additional offtake and pricing risk.

7.3 Economics of LNG export projects

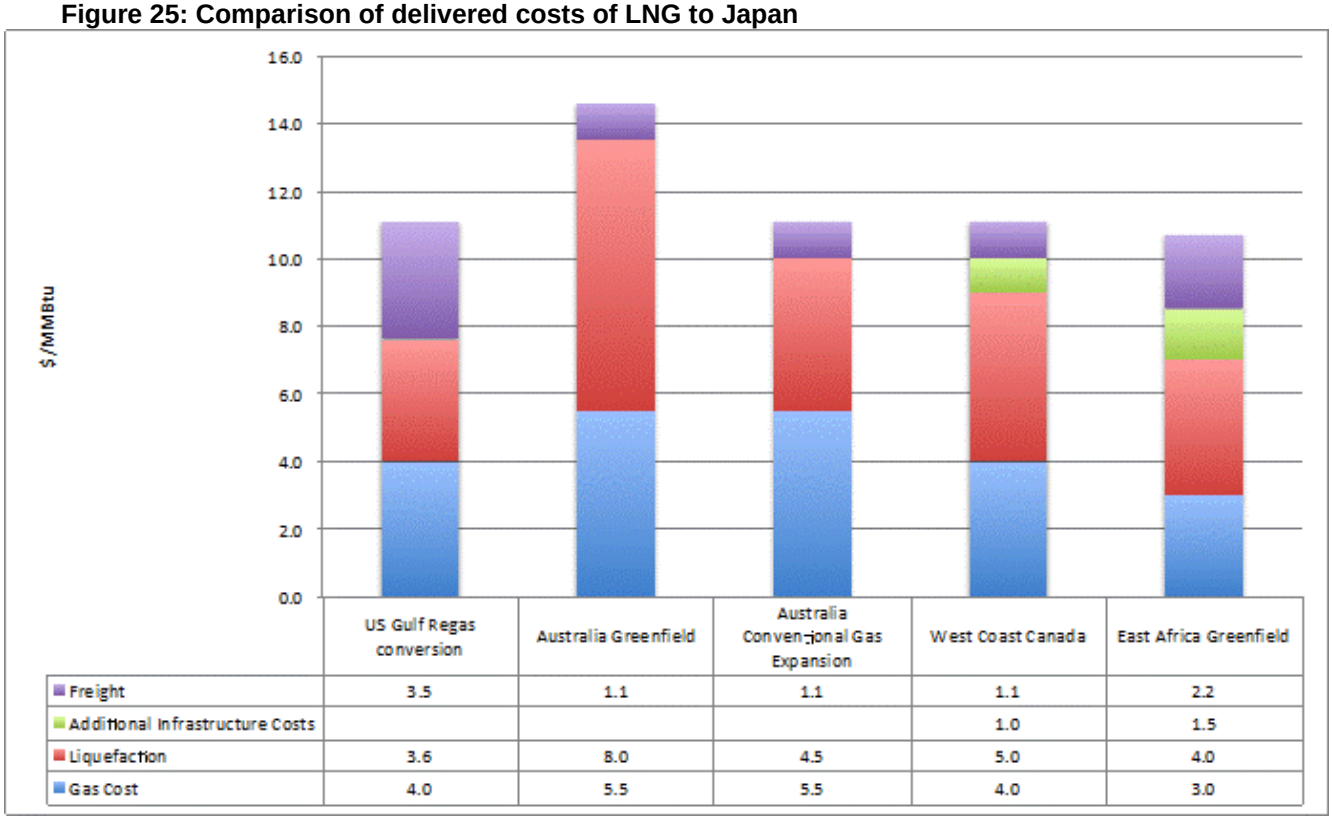
This new pricing challenge is reflected in our analysis of the competitiveness of Australian LNG projects shown in Figure 25, which demonstrates the cost build-up from different LNG supply sources to Japan. What is immediately clear is that Australian greenfield projects are very expensive, meaning that new projects are very unlikely to be commercial and even existing projects under construction could face problems achieving expected project rates of return if customers start to insist on price renegotiation if and when the arrival of US LNG exports creates a momentum both for a new price formation mechanism and lower prices.[116] Beyond the Australian greenfield projects, though, it can be seen that all the four potential supply countries analysed can land LNG in the Asian markets at similar cost levels, although the balance of cost is different within each. The US cost is driven by the Henry Hub price, here assumed to be $4/MMbtu, but also reflects a lower liquefaction cost, as the export plant is in some cases built on the same sites as existing regasification terminals and have skilled labour available at a lower cost than Australia, but shipping costs to market are higher. Meanwhile, Australia may have feed gas that is marginally more expensive, but has lower shipping costs to the Asian markets, while the brownfield projects have much lower liquefaction costs than the greenfield projects thanks to infrastructure synergy benefits. West Canada has short shipping distances (similar to Australia), but the gas price is high due to the greenfield nature of the unconventional reserves that are being developed, and there is a further cost, estimated at $1/MMBtu, to move the gas approximately 1,500 km from the gas fields to the coast, over the Rocky Mountains. East Africa has relatively low gas costs, although the gas is dry and does not contain any NGLs, and furthermore the

[115] For a more complete assessment of this issue see 'Challenges to JCC Pricing in Asian LNG Markets', Rogers and Stern (2014)

[116] The advent of Henry Hub based pricing does not necessarily imply a lower price environment, as this will also be driven by the overall global supply and demand balance for LNG. Nevertheless, US LNG has provided the catalyst for a discussion of price levels and a new drive by consumers for lower prices from all new projects.

liquefaction costs are unknown (we have assumed $4/MMbtu here) while we have also assumed that there will be a premium that has to be paid for additional costs to provide for infrastructure that is not readily available in the region (See OIES Paper NG74 “East Africa Gas – Potential for Export, March 2013

Figure 25: Comparison of delivered costs of LNG to Japan



	US Gulf Regas conversion	Australia Greenfield	Australia Conventional Gas Expansion	West Coast Canada	East Africa Greenfield
Freight	3.5	1.1	1.1	1.1	2.2
Additional Infrastructure Costs				1.0	1.5
Liquefaction	3.6	8.0	4.5	5.0	4.0
Gas Cost	4.0	5.5	5.5	4.0	3.0

Source: David Ledesma assumptions and analysis; Ledesma (2013)

However, it is not just the delivered cost of LNG that will determine whether an LNG project will be developed, with political and shareholder factors as well as technical and commercial issues also being pertinent. Table 15 below sets out a qualitative review of project development factors that the authors believe are key considerations in determining which projects will go ahead, highlighting the fact that Australian brownfield schemes rank highly when compared to their global competitors.

Table 15: Analysis of project development factors for the five primary new LNG supply sources

	Gas Reserves	Project Economics and development status	Sales of LNG	Distance to market	Government & Geopolitical Factors	Sponsors	Ability to finance
Australia Brownfield	Medium	Medium	Medium	High/Medium	Medium	High	High
Australia Greenfield	Medium	Low	Low	High/Medium	Medium	High	Medium
US Gulf	High	High	High	Low	Medium	Medium	Medium
West Canada	Medium	Medium	Low	High/Medium	Medium	Medium	Medium
East Africa	High	Low/Medium	Medium	Medium	Low/Medium	Medium	Low/Medium
Russia East	Medium	Low/Medium	Medium	High	Low/Medium	Low/Medium	Low/Medium

High = Supports project development
Medium = Some uncertainty
Low = Works against project development

Source: David Ledesma assumptions and analysis

Gas reserves

Clearly it is essential that sufficient gas reserves exist to underpin the development of a project, usually 10-13 Tcf of gas for an 8 mtpa LNG plant to operate for 20 years. In the case of East Africa there are enough reserves to support the initial development of a significant LNG hub, and in West Canada to support the development of several LNG export projects. In Russia, although project developers say that there are sufficient reserves to develop the planned projects, allocation of the available gas between projects is not firm despite the recent agreement with China that will involve the construction of the Power of Siberia pipeline. And concerns remain about the distance between gas fields in East Siberia and the liquefaction plants on the Pacific coast. In the US gas will be sourced from the entire pool of the country's production, which continues to expand and where projections suggest no shortage in the foreseeable future. Meanwhile in Australia conventional projects in Western Australia and the Northern Territory have adequate reserves dedicated to specific schemes, but in Eastern Australia the availability of sufficient coal seam gas reserves of LNG is being questioned and may also be challenged by the growing attraction of domestic sales at rising prices.

Project Economics and development status

A project clearly needs to be economic and while the high costs of greenfield Australian projects are a challenge to project viability, Australian brownfield projects should be commercial and competitive if developed efficiently. The delays and cost overruns in the Australian LNG projects that are under construction, however, will also have raised questions with existing and new LNG buyers as to the reliability of Australian-based companies and contractors to deliver new LNG projects on a timely and economic basis. This could challenge the number of new export-led LNG projects that are developed in the future. Labour productivity in Australia is also of concern to project developers, with the Independent Project Analysis (IPA) consultancy estimating that it took 1.3 hours in Australia to conduct work that would take 1 hour in the US Gulf Coast and that this figure has now increased to 1.35 due to long travel times to remote locations[117]. The primary reason for this low productivity rate is the lack of materials and equipment and the use of less experienced workers because skilled labour is in short supply[118]. That said, LNG buyers who must have LNG, by a specific date, will compare

[117] Young (2012),
[118] WGI (June 2013)

Australia brownfield and expansion projects with greenfield projects in East Africa, West Canada or even North America, and may well conclude that the timing risk of brownfield project expansions should be less uncertain. Australian project expansions might therefore have a greater likelihood of proceeding and thus represent a lower project development risk than schemes being developed in other countries.

Sales of LNG

In general LNG buyers look to diversify of their LNG supply portfolio, as a means to gain secure LNG supply. While on one hand buyers may seek to diversify supply by contracting with a new greenfield project (with FID as a supplier condition precedent), this does carry additional risks, in that the planned LNG project may be cancelled or indefinitely deferred, leaving the LNG buyers without the expected new supply. LNG from expansion projects or de-bottlenecking[119] is more reliable and new LNG supply from stable suppliers, with a track record for delivery, is therefore attractive to LNG buyers. Expansion projects can also develop new LNG capacity in a shorter timeframe than new greenfield projects. This is a huge positive that many projects rely on in expanding their projects and one that Australian projects can deliver. Also, Asian LNG buyers are seeking to secure LNG at the lowest possible price and diversify the pricing of LNG away from oil-related formulae. Woodside's CEO, Peter Coleman said in August 2013 that Asian LNG prices remained strongly linked to oil prices as "for the balance of the decade US LNG export quantities will be small and therefore have limited influence on weighted average prices".[120] On the other hand Australia's Bureau of Resources and Energy Economics (BREE) said in October 2013 that buyers in the Asia Pacific are increasingly seeking to increase their exposure to Henry Hub. "Should the US move faster on LNG project development/approval, and this pricing model continues to be favoured, these downward [price] pressures may become stronger"[121].

It is the view of the authors that, at least over the next 5 years, a hybrid pricing basis (with an oil and hub pricing element) will develop or an oil price with a lower slope, which may fall to as low as 12-12.5%. Even at this slope, assuming oil prices over $100/bbl, new LNG supply from expansion projects should be economic. Should market prices fall (whether hub- or oil-related), project economics will come under strain and developers may seek tax breaks from the government. Also, as project economics get tighter, so the ability to absorb the additional costs of any new regulations, such as CO_2 or domestic gas supply obligations, would be harder to support.

Distance to market

Russia is by far the best positioned new source of LNG for Asia in terms of geography, but Australia is also relatively well positioned. This has implications not just for cost but also for security of supply, as buyers feel that the risk of their supply being interrupted is reduced by a shorter distance from LNG source to market.

[119] Debottlenecking an LNG plant involves identifying the parts of the plant that are constraining production and removing the constraint. It might involve increasing the size of some of the pipework, increasing the power of the compressors and/or increasing the capacity of the gas treatment units. The modifications will vary from plant to plant and will be specific to that plant. The work is typically carried out during a maintenance shutdown and can often realise an additional 10% of LNG production. (Source: MEES)

[120] Platts Commodity News "Australia's Woodside renegotiating prices on 14 sales contracts", 21/8/13

[121] Argus Global LNG page 13 "Bree sees more pressure on oil-linked pricing", October 2013

Table 16: Distances of various LNG producing countries to Asian gas market

	Distance to Japan (NM)	Freight Cost ($/MMBtu)
US Gulf	9220	3.5
Australia NW Shelf	3700	1.1
Australia Gladstone	3770	1.1
W Coast Canada	3934	1.1
East Africa	7740	2.2
East Russia (Sakhalin)	904	0.3

Source: David Ledesma assumptions and analysis

Government & Geopolitical factors

The development of large infrastructure projects, such as LNG, can be heavily influenced by the support that the project has from the host government, its relationships with the buyer country, and the relative political stability of both. Whereas Australia, US and Canada are perceived as relatively stable (with respect to LNG export policy), East Africa offers a more ambiguous environment (especially with the forthcoming presidential election in Mozambique in October 2014 and with the Tanzanian government's support for LNG exports being uncertain due to rising domestic gas demand), while the details of Russian LNG export policy remain unclear and could change. Having said this, Australia is also not without its issues, with commentators arguing that the government should have played a more active role in regulating the development of LNG projects to avoid the overheated labour and capital markets,[122] and that the country does carry the risks of an uncertain tax regime, excessive bureaucracy and environmental opposition. Furthermore, in the US there is a clear regulatory risk surrounding the approval of LNG export projects, although this does appear to be reducing as the prospects for unconventional gas production continue to improve. As a result, only Canada would appear to offer a fully supportive political regime, although with remaining uncertainty in its fiscal regime, as the country seeks to replace pipeline exports to the US with LNG exports to Asia.

Sponsors

To develop an LNG project quickly, one would expect a clear alignment of project sponsors and a shareholder group that includes skilled LNG project developers with sound financial backing. This is the case in Australia, but less so in the USA (where Cheniere, Sempra and Freeport LNG have been the leaders in US Gulf LNG exports, companies with little LNG expertise) and some projects in Canada (Petronas are leading the pack and its Canadian project will be the first where it has been lead developer). In East Africa and Russia, larger shareholding groups and those that include inexperienced LNG project developers could slow down the progress of project development timelines. In Australia, the existing projects have established shareholder groupings, which should facilitate project expansions with limited need to renegotiate shareholder terms. Newer greenfield projects however, will need to secure additional shareholders to share costs and attract buyers of LNG, which could delay projects further

Ability to finance

In order to secure third party finance, projects must be structured correctly, be economic, have the necessary gas and technology and have the correct shareholders involvement. Government support is also vital. Australian brownfield projects have a real financing advantage over greenfield projects,

[122] http://natgas.info/about/gas-blog/99-can-australian-lngrojects-stay-competitive, May 2013

as shareholders will be able to fund expansions through project cashflows and potential low-risk financing of existing assets.

Our overall conclusion is that Australian brownfield projects can be competitive relative to their global peers both on an economic basis and in relation to a number of the other "above ground" risks that are relevant when LNG projects come to be approved. Another important factor, which is noticeable both in the existing projects under development and in the proposed projects (Tables 4 and 14) is that many of the projects have equity participation from Asian buyers, further suggesting that they will be more likely to proceed. As a result, although there is still a lot of concern in Australia that the country may have priced itself out of the market for new LNG supply, we believe that the worst of the high cost environment may now be in the past. As a result worries expressed by the Australian Petroleum Production and Exploration Association (APPEA), who have argued that Australia may lose nearly $100 billion of investment if LNG investors decide to not to build new projects in Australia, and by McKinsey, who in June 2013 stated that over $150 billion of investment could be lost if Australia does not cut project costs by 20-30%, although valid based on recent experience may be less relevant as Australia enters an era of brownfield rather than greenfield development.[123]

7.4 FLNG as another alternative to reduce costs

With pressure on costs, concerns over speed of project development and increasing environmental concerns over land-based LNG projects in the remote regions of Australia, some LNG developers have looked to FLNG. Shell is in the vanguard with its Prelude LNG project, whose vessel is currently under construction in the Samsung yard in South Korea. Shell has not revealed many details about the cost of Prelude, but when the project was approved it indicated that Prelude would cost US$10.8 to US$12.6 billion Assuming $12 billion the unit cost of capacity is US$3,330/MT which is still lower than other Australian LNG projects (see Table 5 above), and if the volume of the liquids is taken into consideration, this unit costs falls to US$2,300/MT, which is above the US$1,500/MT assumed for the Australian expansion liquefaction cost in Figure 25 above, but certainly cheaper than the greenfield LNG projects[124]. Shell's strategy is to "build one, build many" and this could reduce costs further as additional fields are developed.

Furthermore, Woodside has announced that it has scrapped its original plans for the Browse LNG project, which had been to build a greenfield project onshore at James Price Point, in favour of a lower cost FLNG option[125]. This has resulted in some negative comment from Western Australian politicians, who would like to see the project developed onshore as it would lead to more domestic employment and development of local infrastructure. In addition it has also raised the issue of the split of responsibilities between the State and Federal governments. The Western Australia state government has jurisdiction over part of the Torosa fields (with the rest of the gas coming from the other part of the Torosa field, Brecknock and Calliance) and it may not permit gas from the Western Australian portion of Torosa to be used to supply an FLNG project. The Western Australia premier has also said that Western Australia should get 30% of the tax revenues from the Torosa field, but this has not been agreed at a federal level.[126]

ExxonMobil has also announced that it is considering the development of a 7 mtpa FLNG facility to commercialise its Scarborough & Jupiter gas fields, located 280km south-west of Onslow, while

[123] WGI (June 2013)
[124] FLNG cost includes both the liquefaction and the gas production cost, leaving out only royalties/taxes
[125] Heren Global LNG Markets 9th January 2014 "Browse supply deal with Japan's MIMI lapses"
[126] Argus Global LNG p12 "State Government could sink Browse FLNG", October 2013

GDFSuez was considering a 2.4 mtpa Bonaparte FLNG facility to commercialise its Petrel, Tern & Frigate gas fields, but in June 2014 announced that it was abandoning the project for economic reasons[127]. PTT is examining the possibility of using an FLNG facility to commercialise its Cash-Maple field. WA's approach to Browse FLNG is not expected to impact on ExxonMobil, GDFSuez and PTT's planned FLNG projects as the ExxonMobil project is further from shore and the other two are in areas under the jurisdiction of the federal government, and all three are believed to be considering their FID decisions.

As a result, the authors expect that once the technology becomes proven FLNG projects will proceed relatively rapidly in Australia. However, this does not mean any immediate progress, as Prelude is expected to start-up in 2017, and a comparable Petronas FLNG project, to be located offshore Sarawak in Malaysia, is expected to begin in 2016. We would therefore not expect any new FIDs for FLNG projects until after these dates, but this would nevertheless imply the potential for a number of new schemes after 2020.

7.5 Which new projects will proceed?

This analysis would suggest that there is reasonable potential for Australian brownfield and FLNG projects to be developed once the current projects under construction have been completed. Table 14 above identifies 6.6mtpa of specific FLNG projects plus a further 10.5mtpa of capacity that is now being considered for FLNG, while the total for brownfield projects from conventional fields in Western Australia and Northern Territory is 26.2mt. Meanwhile there is also the potential for brownfield expansion of the CSG-based LNG projects in Eastern Australia, although as we suggested in our analysis above we are only really confident in the potential to expand the APLNG project using gas from the deferred Arrow LNG scheme, which could provide another 4mtpa of capacity. As a result, a theoretical possibility for brownfield and FLNG in the future is just under 50mtpa of extra capacity.

Cleary there will be competition to sell LNG in the global gas market which means that all of this potential is unlikely to be realized, but the authors would expect a significant amount to reach the market as Australian brownfield expansions enjoy considerable economic advantages. It can also be expected that project developers will seek to expand current projects to recover some of the financial returns that they were originally expecting but have been diminished by the cost overruns and delays that we have discussed above. That said, the experiences of the past five years may have dented Australia's reputation as a reliable LNG project developer, with a large volume of other new potential supply globally, and new projects will have to "sell" themselves well to convince consumers that LNG will be delivered on time and budget.

It is difficult to be specific about exactly which projects will go ahead, although identifying those with Asian consumers as project sponsors can provide a useful pointer, but the authors are of the view that, subject to market conditions, 20-25 mtpa of new LNG capacity could take FID by 2020, with one additional train on the east coast and the remainder on the North-West Shelf.

[127] http://www.reuters.com/article/2014/06/19/gdf-sue-santos-ltd-lng-idUSL4N0P01X020140619

8. Conclusions

The Australian domestic gas market is in fact comprised of three disconnected markets, although each is now starting to face similar challenges. The dramatic expansion of the country's LNG capacity through the construction of 7 new projects virtually simultaneously has caused cost inflation and project delays due to labour shortages and operational constraints. In addition, the sale of so much LNG to the export market has started to have an impact on gas availability in the domestic market, causing concerns over gas shortages and rising prices. The combination of all these issues has raised questions about whether the growth in Australian LNG exports can continue beyond the additional 62mtpa of capacity that is currently being built and which will make the country the largest LNG capacity holder in the world by 2018.

Having said that the issues are country-wide, it is nevertheless the case that the Western Australia and Northern Territory markets are very much export-driven as the size and cost of the projects being developed are both too large to find sufficient demand locally and too expensive to be economic at currently prevailing low domestic prices. As a result they have been conceived as LNG projects for the Asian market, with some gas reserved by law for domestic customers in Western Australia. However, this gas reservation policy has only been marginally successful in keeping prices down, and as a harbinger of the issues soon to be faced in the east the domestic gas price has been rising towards export netback levels. The new LNG schemes in Northern Territory and Western Australia, which account for the majority of the country's new gas developments, have also been experiencing problems of their own, with cost overruns and project delays undermining the economics of the projects and calling into question the future expansion of the industry. The weakening of the Australian dollar since 2012 has helped to ease some of the cost pain for some projects, but nevertheless it seems likely that only brownfield expansions, or floating liquefaction, will be seriously considered in the near future, with new greenfield land-based projects likely to be delayed until the future of the global LNG market becomes clearer.

In contrast the gas market in the East has historically been very much based upon supply to domestic consumers, albeit that some states such as Queensland, Victoria and South Australia have been net exporters while New South Wales and Tasmania have been net importers. However, it has been transformed into a more globally-linked market by the imminent completion of three new LNG export projects at Gladstone, with the situation being further complicated by the fact these projects are based on CSG reserves, the development of which is still subject to timing uncertainty. While the reserves in place appear to be sufficient, or very nearly so, on an overall basis, individual projects (especially the Santos-sponsored Gladstone LNG) currently lack the resources to meet their export contracts and are contracting for gas that might otherwise have gone to domestic customers. Meanwhile uncertainty over the deliverability of supply in the initial stages of CSG development at QCLNG has also led that project to contract for significant amounts of third party supply, again increasing pressure on the domestic market.

The overall result has been that the price of gas in States in the eastern region has risen sharply over the past two to four years, and gas has become less readily available under long-term contracts. This has led both to demand expectations being reduced (especially in the power sector) and to industrial (and to an extent residential and commercial) customers having to pay prices that are now approaching export netback levels. As a result some consumer lobby groups have begun to call for a gas reservation policy, or some similar review of exports, to be introduced in order to make gas available and keep prices down. However, it would appear at present that any such move would not

only be met with skepticism by regional politicians but could also be very hard to implement due to potential conflicts between federal and state law.

As a result, there would appear to be no threat to the progress of the current projects that are under construction, and the progress being made at all seven plants would suggest that they will come onstream in the period 2014-2018 as planned, leading to a total of 61.8 mtpa of new LNG export capacity being added to Australia's LNG industry. A more difficult question concerns the potential for new LNG capacity in Australia. Australian LNG will face considerable competition from other LNG supply countries, both on a cost and reputation basis, but Australia's existing LNG production track record, and relative closeness to market leads the authors to believe that new LNG projects will be developed in Australia. These projects will be developed as expansions to existing facilities or FLNG projects, with a realistic estimate being that 20-25 mtpa of new LNG capacity could take FID by 2020. One additional train is likely on the east coast with the remainder on the North-West Shelf. The key issues on the East Coast are questions of gas availability and also the fact that if domestic gas prices do continue to rise towards export netback levels, as currently seems likely, there may be little incentive for gas producers to look for more export demand if local customers are prepared and able to pay international level net back gas prices.

In overall conclusion, it would appear that despite the problems that have been encountered across Australia's LNG industry over the past few years, the country will become the largest LNG exporter in the world by 2018. Future plans beyond the current projects under construction are more uncertain, but the economics of brownfield developments in Australia would appear to be attractive relative to global competitors in East Africa, Russia, Canada and even the US, and as a result some additional expansions are likely to occur. However, in the west and north these may depend upon the industry's ability to maintain cost control and manage contractors more effectively, while in the east the establishment of sufficient CSG reserves and productive capacity remains a challenge both for existing projects and future expansions. The environmental and political issues involved with extensive CSG development may prove difficult to manage, but it seems to be increasingly clear that all the State governments will probably have to be prepared to accept that gas prices need to respond to market forces and rise towards export netback levels, even though this could have an impact on energy supply costs to domestic industry and the overall economy.

Appendix 1 – Australian Gas Basins

Northern & Western Markets

The Carnarvon Basin has 71,855PJ (67.8 Tcf) of gas reserves (50.8% of Australian reserves). Gas from the Carnarvon Basin supplies the North West Shelf and Pluto LNG export facilities and 98% of domestic gas in Western Australia (30% of Australia's domestic sales). By 2018 the Gorgon and Wheatstone LNG export projects will also be in operation. There is also estimated to be 9,540 PJ (9 Tcf) of shale gas in the Carnarvon Basin[128].

The Browse Basin has 17,384PJ (17.3 Tcf) of reserves, which is 12.3% of Australian reserves[129]. These reserves are intended for export and it is very unlikely that the gas would be available for the domestic market before 2023[130].

The Bonaparte Basin has 1054PJ of 2P reserves (1.05 Tcf), 0.7% of Australia's reserves, which are owned mainly by Eni Australia (80%). Production from the Bonaparte Basin increased from 8.5 PJ (0.2 Bcma) in 2009/10 to 19.6 PJ (0.5 Bcma) in 2010/11. Gas is carried by pipeline to the Northern Territory for processing for export and for domestic consumption.

The Perth Basin has 53PJ (0.05 Tcf) of reserves. Gas from the Perth Basin is mostly onshore and only supplies the domestic market and represents only 1.7% of domestic gas in Western Australia[131]. There is also estimated to be 16,960 PJ (16.0Ttcf) of shale gas and 27,666PJ (26.1 Tcf) of tight gas in the Perth Basin[132].

The Amadeus Basin has 138PJ (0.14 Tcf) of 2P reserves, only 0.1% of Australian reserves, which are owned by Santos (68.2%) and Magellan (31.8%). The Amadeus Basin is located onshore in the centre of the country and has seen production fall from 10.2PJ (0.26 Bcma) in 2009/10 to 1.6PJ (0.04 Bcma) in 2010/11, with gas from the Bonaparte Basin displacing the Amadeus Basin as the Northern Territory's main source of gas.

The Canning Basin is currently being explored for gas and there is no production and no gas infrastructure in place. A number of companies (Apache Energy, Buru Energy, ConocoPhillips) are exploring for what is estimated to include 477,000PJ (450 Tcf) of shale gas and of 14,946PJ (14.9 Tcf) of tight gas[133].

The Joint Petroleum Development Area (JPDA), to the north of Darwin is shared with East Timor.
The JPDA was established by the 2003 Timor Sea Treaty, between Australia and Timor Leste and provides the framework for all petroleum exploration and development within the JPDA. The area contains the Greater Sunrise gas and condensate fields, which are estimated to hold 5,400PJ (5.1 Tcf) of gas and 226 million barrels of condensate. The Timor Sea Treaty states that any deposit that extends beyond the boundary of the JPDA will be developed as a single entity for management and development purposes, ensuring that neither country can develop overlapping fields unilaterally[134]. The issue is that Timor Lest wants to develop the Sunrise gas resource as a land-based LNG export

[128] IMOWA (2014) p.120
[129] http://www.aer.gov.au/node/23226
[130] IMOWA (2014) p 115
[131] WA GSOO AEMO (2013a)
[132] IMOWA (2014)
[133] IMOWA (2014)
[134] http://www.innovation.gov.au/resource/UpstreamPetroleum/Pages/JointPetroleumDevelopmentAreaandGreaterSunrise.aspx

plant in Timor Leste, while Australia wants the best commercialisation route, either land-based in Australia or using floating FLNG. This political impasse has delayed development of the project.

Eastern Markets

Surat-Bowen Basin is located in northern Queensland and extends into northern New South Wales. The Surat-Bowen Basin has 41,372PJ (41 Tcf) of 2P reserves, which represents 29.2% of the reserves in Australia. Gas from this basin accounts for approximately 22.6% of production in Australia with the main producers being BG (20.5%), Origin (16.7%), Conoco Phillips (16.7%), Sinopec (11.2%) and Santos (8.6%)[135].

Cooper Basin, located in the north-east of South Australia, which crosses into Queensland. The Cooper Basin has 1913PJ (1.9 Tcf) of conventional reserves[136]. Gas from the Cooper Basin supplies 7.8% of Australian domestic sales and is produced by Santos (64.6%), Beach (21.2%), and Origin (13.3%). Until 2012 the basin produced conventional gas and production was declining but now shale gas is also being produced and this has been increasing output by as much as 14% in recent years. The Cooper Basin may become the centre of the next unconventional gas region in Australia following commitments by companies to drill for tight gas, shale and deep coals. Origin Energy and independent Senex in February 2014 agreed to start a predevelopment plan for tight gas sands areas. The opportunity, if gas is developed, is focused on developing reserves for LNG export. Chevron and Beach Energy are developing the Nappamerri Trough gas joint venture in South Australia and Queensland that has potentially huge shale gas reserves of 200,000PJ (200 Tcf)[137].

The Gippsland Basin is located offshore Victoria and has 3720PJ in 2P reserves (3.7Tcf) and gas from the Gippsland Basin supplies 24.8% of the Australian domestic market and is produced by BHPB (48.0%), ExxonMobil (48.0%), Nexus (4.0%). Gas is brought onshore and processed at Longford on Victoria's southern coast.

The Otway Basin is located offshore Victoria and has 820PJ in 2P reserves (0.8 Tcf), and supplies 9.9% of Australian domestic market. Gas is produced by Origin (30.9%), BHPB (20.8%), Santos (17.9%), and Benaris (12.8%), brought onshore and processed at Iona on Victoria's southern coast. Gas is brought onshore and processed at Longford on Victoria's southern coast.

The Bass Basin is located offshore Victoria and Tasmania and has 250PJ in 2P reserves (0.25 Tcf)[138] and supplies 1% of Australian domestic sales. Gas is produced by AWE (46.9%), Origin (41.8%) and Toyota Tsusho (11.3%) and is processed on Victoria's southern coast at Lang Lang. Gas is brought onshore and processed at Longford on Victoria's southern coast.

[135] http://www.aer.gov.au/sites/default/files/Chapter%203%20-%20Upstream%20gas%20markets%20A4.pdf
[136] Owned by Santos (63.4%), Beach (18.0%), Origin (12.4%) and Drillsearch (6.2%).
[137] Argus Global LNG, March 2014, page 12, "Cooper Basin gas venture take shape"
[138] Owned by AWE (46.3%), Origin (42.5%), and Toyota Tsusho (11.3%)

Appendix 2 - Governance and regulation

Energy in Australia is governed by Commonwealth and State Government, as defined by the constitution, intergovernmental agreements and market governance agreements. Since energy is of national significance, the Council of Australian Governments (COAG) agreed to establish the Standing Council on Energy (SCE). SCE comprises representatives of the Commonwealth, State and Territory Governments, which cooperate to develop harmonisation of energy policy, legislation and market rules. The SCE process has created the National Gas Law, National Gas Rules, and National Energy Retail Rules, which are agreed and applied by each Australian state and territory and the Commonwealth, with some variations between jurisdictions.

Reforms by SCE include the formation of the National Gas Market Bulletin Board, an annual Gas Statement of Opportunities, the Short Term Trading Market in Sydney, Brisbane and Adelaide, and the separate short-term wholesale market in Victoria.

The national framework defines three institutions for energy market regulation and operation:

1. Australian Energy Market Operator (AEMO) - is responsible for the operation and administration of the electricity and gas wholesale and retail markets in all jurisdictions except Western Australia and the Northern Territory. AEMO creates the Gas Statement of Opportunities.
2. Australian Energy Market Commission (AEMC) - is responsible for rule-making and market development in the national electricity and gas markets, reviewing energy market frameworks and providing advice to the SCER.
3. Australian Energy Regulator (AER) - is responsible for the economic regulation of covered gas transmission and distribution networks and enforcing the national gas law and national gas rules in all jurisdictions except Western Australia. The AER also creates the State of the Market Reports.

The three tiers of economic regulation include different levels of regulation from full cover to no regulation at all (uncovered). Pipeline owners of fully regulated assets must provide open access arrangements for a reference service and a public tariff for that service. The regulator (AER) reviews this tariff against the revenue required for efficient costs and return on capital and sets the final tariff. Pipelines owners of lightly regulated assets determine their own tariffs but the AER may arbitrate in disputes. All jurisdictions except Victoria and South Australia regulate retail prices, although only New South Wales regulates prices for small customers. Prices are set by state-based agencies using a building block approach, or a benchmark retail cost index.

Each state provides financial incentives to facilitate the development of gas reserves investment, improved job prospects, infrastructure and create economic development. Governments also receive taxes and royalties as income from these activities. Petroleum royalties and taxes are paid at different rates depending on whether they are offshore, or onshore, and in which state they are located.

Onshore and offshore tax rates

The Petroleum Resource Rent Tax (PRRT) is a profit-based tax levied at 40% of net revenues (sales receipts less eligible expenditures) from gas projects[139]. This is paid for onshore and offshore oil and gas developments.

Royalty Rate

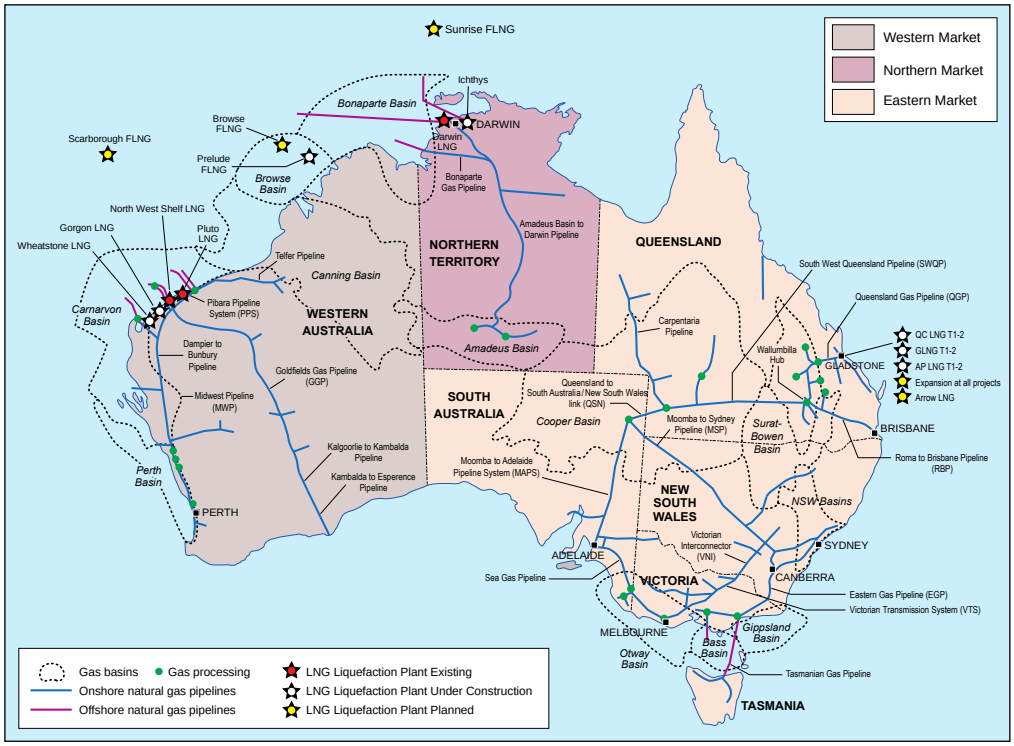
Offshore petroleum royalties currently only apply to the North West Shelf (NWS) production area and state and territory waters. Royalties do not overlap with the Resource Rent Royalty regime[140].
Onshore Royalty rate varies by state:[141]:

- New South Wales - 10% of the value at the well-head of the petroleum (before 1 January 2013, the rate of royalties for the first five years of commercial production was nil; and for the sixth year 6%, rising by 1% each year up to 10% of the well-head value in the tenth year).
- Northern Territory - 10% of the gross value at the wellhead of all petroleum products produced from the licence area
- Queensland - 10% of the wellhead value
- South Australia - 10% of the net post-wellhead sales value
- Victoria - 10% of net wellhead value of the petroleum produced
- Tasmania - 12% of the gross value of petroleum at the well head
- Western Australia - 10-12.5% of the wellhead value of petroleum produced. In 2009, the royalty rate for tight gas was reduced from 10% to 5%.

[139] Australian Government Department of Industry (2014)
[140] Australian Government Department of Industry (2014)
[141] Montoya, D. (2012)

Appendix 3 - Gas Pipelines

Map 1: Australian domestic market, major pipelines and LNG export projects



Source: Author research

Maps 1 and 2 show the gas network infrastructure in Australia. Details of the pipelines include:

A. Western Australia

a) The Goldfields Gas Pipeline (GGP) (owned by APA Group) moves gas 1380km south-east from the offshore production sites in the Carnarvon Basin and the Northwest Shelf in the north-west of the state, to the Pilbara, Murchison and Goldfields mining regions for industrial use and power generation. The GGP ends in Kalgoorlie and extends to Esperance through the Kalgoorlie Kambalda Pipeline (KKP) (owned by APA Group) and the Kambalda to Esperance Gas Pipeline (KEGP) (owned by Esperance Pipeline Company Pty Ltd). These lines serve mining, industrial, commercial and domestic consumers in the south of Western Australia

b) The Dampier to Bunbury Natural Gas Pipeline (DBNGP) (owned by DBP Transmission) runs approximately 1600km from the Carnarvon Basin to population centres and industry in the south-west of the State. This pipeline links and runs with the Parmelia Gas Pipeline (PGP) (owned by APA Group), which transports gas from both the Perth Basin and Carnarvon Basin to industrial markets in the wider Perth area.

c) The Midwest Pipeline (MWP) (owned by APA Group) moves gas 353km from the DBNGP at Geraldton to power generators for mining processes in Windimurra and Mt Magnet.

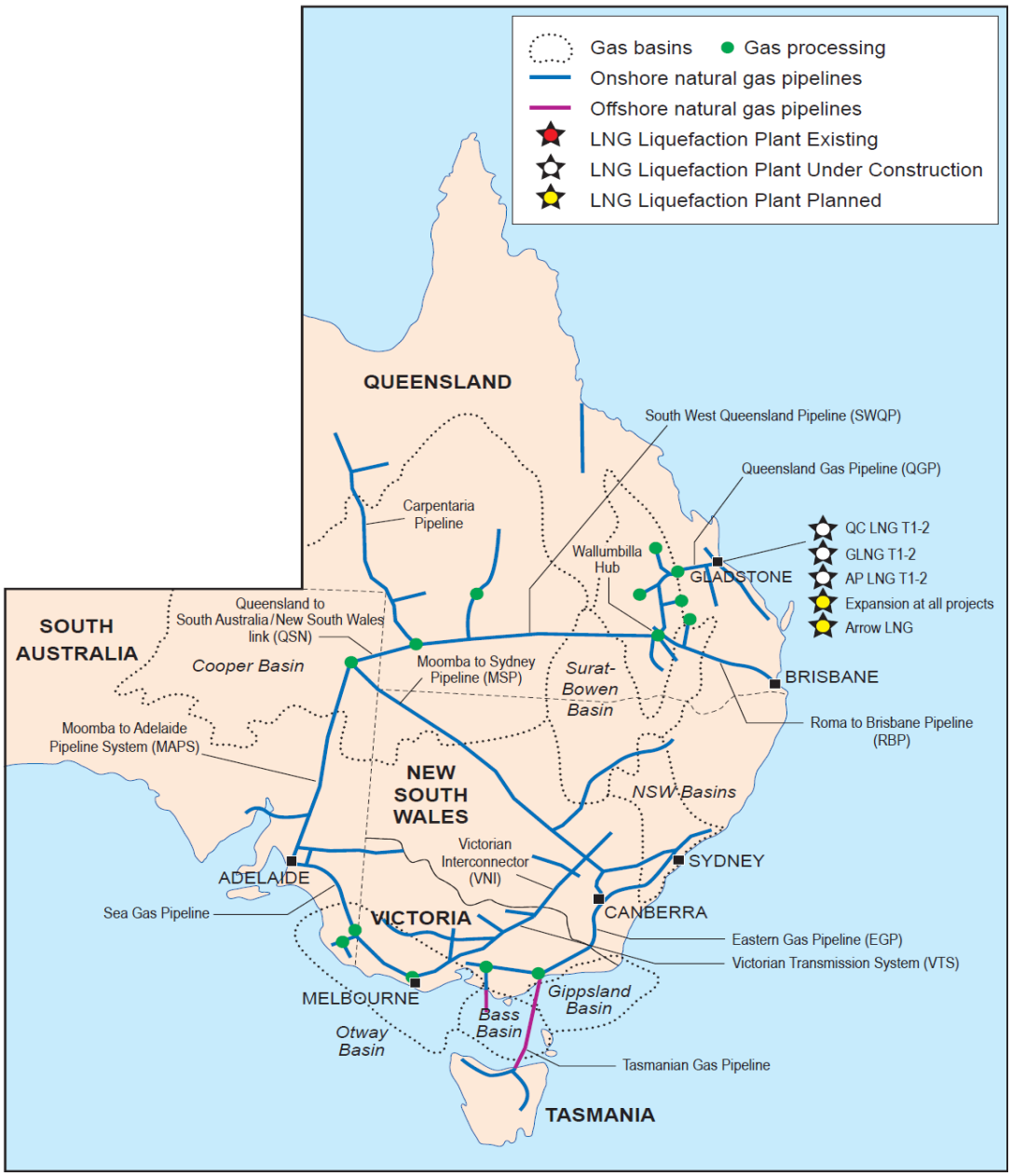
d) The Pilbara Pipeline System (PPS) (owned by APA Group) runs from the Carnarvon Basin to the Pilbara region. It includes the Pilbara Energy Pipeline (PEPL), which runs from the Carnarvon

Basin to power stations located in Karratha and Port Hedland. The PELP is connected to: mines in the Pilbara by the Telfer gas pipeline; Woodside's New South Wales processing plant at Dampier by the 24km Burrup Extension Pipeline; mining operations at Wodgina by the 80km Wodgina Lateral; the Horizon Energy Power Station at Karratha by the 5km Karratha Lateral.

B. Northern Australia

The Bonaparte Gas Pipeline delivers gas from the Bonaparte Basin offshore from the Northern Territory to the Amadeus Pipeline. Gas then flows north to Darwin and south to Alice Springs via the Amadeus Pipeline (owned by APA Group).

Map 2: Eastern Australian Gas Infrastructure



Source: OIES

C. New South Wales

a) Moomba Sydney Pipeline (MSP) - owned by APA Group, the MSP is the main line in New South Wales, which runs 2029km to link the Cooper Basin in north-eastern South Australia with domestic and industrial users in Sydney on the east coast. The MSP picks up coal seam gas from AGL in the Sydney Basin at Camden. Laterals (owned by APA Group) from the MSP feed rural New South Wales, including the Central West and Central Ranges Pipeline. The Young to Wagga Pipeline (which is currently being looped for 61km) takes gas from the New South Wales-Victoria Interconnect (VNI) to the MSP.

b) Victorian Interconnector (VNI) - owned by APA Group, the VNI transports gas bi-directionally between the Victorian Transmission System (VTS) near Culcairn, through the Young to Wagga lateral to the MSP. Gas from the Bass Strait is then transported to Sydney via the MSP.

c) Eastern Gas Pipeline (EGP) - owned by Jemena, the EGP runs 797km from Longford in the Gippsland Basin in Victoria, to Sydney in the north. Gas is supplied to Sydney and regional centres, the most notable consumers being the Bluescope Steel facilities at Port Kembla, Marubeni's Smithfield power station and EnergyAustralia's Tallawarra power station. The EGP and the MSP come within 4km of each other but do not connect.

d) Since gas from South Australia's Cooper Basin is likely to supplement gas supply to the LNG export plants in Queensland as well as supply domestic demand, the most likely source of gas would be offshore Victoria. Gas from the Bass Strait will be treated in Victoria and could be transported via pipeline to New South Wales. Gas could flow to Sydney and regional demand centres through the EGP, or through the VNI then the MSP. Jemena (owner of the EGP) and APA Group (owner of the VNI and the MSP) are currently upgrading the EGP and VNI, which could increase the capacity to transport gas to New South Wales.

e) However, APA Group has applied to operate the MSP bi-laterally. Concurrently, Jemena has applied to connect the EGP with the MSP. These applications in combination would mean that gas from Victoria could be sent north to Queensland and the LNG export plants through the VNI and the EGP, through the MSP to Moomba in South Australia, then to Queensland through the SWQP and on to Gladstone. This would transport gas away from New South Wales rural demand centres, and Sydney.

f) Origin Energy has already signed to deals to transport greater volumes of gas from offshore Victoria to New South Wales, which may provide some temporary relief. However, the capacity of the gas reserves in the Bass Strait to supply gas to New South Wales and Victoria is limited, and as the reserves are declining and Victoria is the state with the greatest gas demand, shortfalls will be exacerbated if gas from Bass Strait is exported through Victoria and New South Wales to New South Wales for the LNG plants at Gladstone.

D. Queensland

The pipeline network in the state has been developed to link the gas supply sources to the market within the state and the southern states.

a) South West Queensland Pipeline (SWQP) - Gas is extracted from the Wallumbilla area of the Surat-Bowen Basin in the south east of Queensland and is transported through feeder pipelines into the SWQP, owned by APA Group. The SWQP collects gas along its length and supplies gas to the Roma and Barcaldine power stations. Gas travels then west, to Ballera in the south-west of Queensland. The capacity of the SWQP has recently been expanded and APA Group is modifying the pipeline to be bidirectional. This will allow supply to be conveyed from the Moomba east to Gladstone and Brisbane. As unconventional gas plays a larger part in the energy mix, the link between Moomba and Wallumbilla, and the smaller feeder pipelines into Wallumbilla will become more important. Further compression on the SWQP is a future possibility. Shippers on the SWQP are vertically integrated with gas production.

b) Carpentaria Pipeline - From Ballera, the Carpentaria Pipeline (owned by APA Group) runs 840km from the SWQP conveying gas north to a mining centre, fertiliser plant and a gas-fired power station in Mt Isa in central Queensland.

c) Queensland to South Australia/New South Wales Link (QSN Link) - owned by APA Group, the QSN Link pipeline, connects the SWQP at Ballera, and the gas production centres at Moomba in the Cooper Basin in South Australia, and then onto the southern markets. Together the QSN and SWQP are 937km long.

d) Roma-Brisbane Pipeline (RBP) - The SWQP pipeline is also contiguous with the RBP, owned by APA Group, which moves gas 438km between the Bowen and Surat Basins eastwards to residential and industrial centres in Brisbane, a fertiliser plant, several power stations and a BP Refinery, and west to the SWQP and Wallumbilla. New inlet stations have been constructed for production from new coal seam gas fields in southern Queensland.

e) Queensland Gas Pipeline (QGP) - From Wallumbilla, the QGP (owned by Jemena) runs north then east to Gladstone/Curtis Island. Gas is transported through this pipe from the Surat Basin, Denison Trough and Bowen Basin to large industrial customers in Gladstone and Rockhampton, including Queensland Alumina, Rio Tinto, Orica, Boyne Smelter and Queensland Magnesia. Gas is also supplied to the retail distribution networks of Gladstone and Rockhampton.

f) Running parallel to the QGP for most of its length is the GLNG Pipeline (owned by Santos), which draws gas from the Bowen Basin.

g) Along the pipelines between Moomba and Brisbane from west to east are also the Eromanga, Adavale, Galilee, Bowen and Surat Basins, which are sites for unconventional gas.

h) Wallumbilla is being established as a virtual gas hub which started trading March 2014 At Wallumbilla, gas can be received from a number of different gas fields in south-eastern Queensland and delivered to Gladstone and Brisbane or to flowed westerly to Ballera or Moomba.

E. Victoria

a) Pipelines in the state move gas from the offshore gas sources to the markets within the state as well as linking the state with the rest of Eastern Australia.

b) Victorian Transmission System (VTS) - moves gas from the three processing plants to industrial and commercial users - domestic use is seasonal, with high consumption for heating in winter, particularly in Melbourne.

c) Victorian Interconnector (VNI) - owned by APA Group, the VNI moves gas bi-directionally between the VTS and the MSP in New South Wales. The Eastern Gas Pipeline (EGP) (owned by Jemena) transports gas north from Longford to Sydney.

d) Sea Gas Pipeline - owned by APA Group, runs 680km along the southern coast of Victoria taking gas from the Victorian gas fields to Adelaide in South Australia, supplying regional markets along its length. This pipeline supplies half of the gas for southern South Australia and will become more important if supply from the Cooper Basin to the south of the state reduces due to gas export.

F. South Australia

Pipelines in the state move gas from the offshore gas sources to the markets within the state as well as linking the state with the rest of Eastern Australia.

a) Moomba Adelaide Pipeline System (MAPS) – Owned by QIC Global Infrastructure, MAPS is South Australia's main gas pipeline, which runs 1184km from gas fields in the Cooper Basin at the north east of the state to Adelaide and regional consumers in the southeast. Two laterals pipelines feed the regional centres of Whyalla and Angaston..

b) Other infrastructure includes the MSP (see section on New South Wales pipelines) that connects the Cooper Basin to Sydney, and the SWQP (see section on Queensland pipelines) that connects the Cooper Basin with the Carpentaria Pipeline to Mt Isa. The SWQP will soon be made bidirectional and will be able to convey gas from the Cooper Basin to Gladstone.

c) Other important pipelines in South Australia include the SGP, the Envestra Gas Network and Pipeline, and the SESouth Australia pipeline to Mt Gambier.

Appendix 4 – Reserve Classifications

Proved Reserves (also known as 1P or P90) - the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions. A probability cut-off of 90% is sometimes used to define proved reserves, i.e. the proved reserves of a field are defined as having a better than 90% chance of being produced over the life of the field. In this sense, proved reserves are a conservative estimate of future cumulative production from a field. (Source: BP)

Economically Demonstrated Resources - a measure of the resources that are established, analytically demonstrated or assumed with reasonable certainty to be profitable for extraction or production under defined investment assumptions. Classifying a mineral resource as EDR reflects a high degree of certainty as to the size and quality of the resource and its economic viability. (Source: Australian Bureau of Statistics)

Sub-Economically Demonstrated Resources (SDR) are similar to EDR in terms of certainty of occurrence but are considered to be potentially economic only in the foreseeable future. (Source: Australian Bureau of Statistics)

Inferred Resources - are those with a lower level of confidence that have been inferred from more limited geological evidence and assumed but not verified. Where probabilistic methods are used there should be at least a 10% probability that recovered quantities will equal or exceed the sum of proved, probable and possible reserves. (Source: Australian Bureau of Statistics)

Potential Resources - are unspecified resources that may exist based on certain geological assumptions and models, and be discovered through future exploration. Undiscovered resource assessments have inbuilt uncertainties, and are dynamic and change as knowledge improves and uncertainties are resolved. (Source: Australian Bureau of Statistics)

Abbreviations

ABARE – Australian Bureau of Agricultural and Resource Economics
ACT – Australia Capital Territory
AEMO – Australian Energy Market Operator
APPEA – Australian Petroleum Production & Exploration Association
BREE – Bureau of Resources and Energy Economics
CSG – Coalseam gas (also known as coalbed methane)
CBM – Coalbed Methane (also known as coalseam gas)
DMO – Domestic Market Obligation
EDR – Economically Demonstrated Resources
EIA – US Energy Information Administration
FID – Final Investment Decision
FLNG – Floating Liquefaction
GSOO – Gas Statement of Opportunities, produced by the AEMO
J/d – Joules per day
Mtpa – Million tonnes per annum of LNG
NGL – Natural Gas Liquids
Pj – Petajoules (equal to one quadrillion (10^{15}) joules)
TJ – Terajoules (equal to one trillion (10^{12}) joules)
SDR – Sub-Economically Demonstrated Resources
SLOPE – The percentage of the Oil price used to determine the LNG price

Bibliography

ABC, (2013): Australian Broadcasting Corporation, Senate Results Summary Federal Election 2013 http://www.abc.net.au/news/federal-election-2013/results/senate/

ABS (2013) Australian Bureau of Statistics, 2013, http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4610.02010-11?OpenDocument

AEMO (2013a), Australian Energy Market Operator, Gas Statement of Opportunities, http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities

AER (2013a): Australian Energy Regulator, State of the Energy Markets 2013 http://www.aer.gov.au/sites/default/files/Chapter%203%20-%20Upstream%20gas%20markets%20A4.pdf

AFR, (2013): Australian Financial Review, SA Libs will allow fracking on farmland September 12, 2013, http://www.afr.com/p/national/sa_libs_will_allow_fracking_on_farmland_uk0NoEEI01RbagweovsP9O

APPEA (2013): Australian Petroleum Production & Exploration Association, Delay the Order of the Day December, 5, 2013, http://naturalcsg.com.au/media/updates/all-news/2013/12/05/delay-the-order-of-the-day

APPEA, (2013b), Domestic Gas Market Interventions International Experience http://www.appea.com.au/wp-content/uploads/2013/04/EnergyQuest-APPEA-Report_20130107_Final.pdf

APPEA (Our natural advantage) http://www.ournaturaladvantage.com.au/about/

Australia in the Asian Century (2012): White Paper: http://www.asiaeducation.edu.au/verve/_resources/australia-in-the-asian-century-white-paper.pdf

Australian Government Department of Industry (2014), Resources Taxation, http://www.innovation.gov.au/resource/Enhancing/ResourcesTaxation/Pages/default.aspx

Australian Mining (2013a) Transparency needed for CSG: operators, 22 July 2013, http://www.miningaustralia.com.au/features/transparency-needed-for-csg-operators

Australian Mining (2013b) Coal seam gas: The explosive debate, August 2013, http://www.miningaustralia.com.au/features/coal-seam-gas-the-explosive-debate

BP (2013): BP Statistical Review of World Energy, 2013, http://www.bp.com/content/dam/bp/pdf/statistical-review/statistical_review_of_world_energy_2013.pdf

BP (2014): BP Statistical Review of World Energy, 2014: http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy.html

BREE (2013a) Gas Market Report: October 2013: http://www.bree.gov.au/publications/gas-market-report

BREE (2013b): Australian Government, Department of Industry, Bureau of Resources and Energy Economics, (2013) Eastern Australian Domestic Gas Market Study, http://www.innovation.gov.au/Energy/EnergyMarkets/Documents/EasternAustralianDomesticGasMarketStudy.pdf

BREE (2014), Bureau of Resource and Energy Economics, Eastern Australia Gas Market Study, Australian Department of Industry, Energy Division, Canberra, http://bree.gov.au/sites/default/files/files//publications/req/REQ-2014-03.pdf

Briscoe, T., (2014) Shale gas exploration go ahead in Tasmania Country Hour, February 6, 2014, http://www.abc.net.au/news/2014-02-06/shale-gas-exploration-go-ahead-in-tasmania/5243116

Chambers, M. (2014), Shell, PetroChina mull Arrow LNG options, The Australian, January 22, 2014 http://www.theaustralian.com.au/business/mining-energy/shell-petrochina-mull-arrow-lng-options/story-e6frg9df-1226807138530#

Chambers M., (2013) Gladstone ramp-up a death blow for domestic demand: Michael Fraser November 11, 2013, http://www.theaustralian.com.au/business/mining-energy/gladstone-ramp-up-a-death-blow-for-domestic-demand-michael-fraser/story-e6frg9df-1226756897676#

Chambers, M., (2013b), Domestic gas reservation and high project costs top energy discussion, Committee for Economic Development of Australia, July 4, 2013; http://www.ceda.com.au/news-articles/2013/07/04/sonenergy

Clifford, C., and Woodburn, J., (2014), Santos CSG MoU raises more questions than it answers February 23, 2014, http://www.abc.net.au/news/2014-02-22/santos-csg-mou-raises-more-questions-than-it-answers/5276996

Coleman, (2013) *In* Platts, Woodside admits onshore Browse LNG project would have cost $80 bil or more December 18, 2013 http://www.platts.com/latest-news/natural-gas/sydney/woodside-admits-onshore-browse-lng-project-would-27744633

Cook, H. (2013), Victorian ban on fracking to stay until 2015, The Age Victoria, November 21, 2013, http://www.theage.com.au/victoria/victorian-ban-on-fracking-to-stay-until-2015-20131121-2xxau.html#ixzz2yB59Zrub

Covacevich, E., (2006), Responses to WA Domestic Gas Reservation Policy, Clayton Utz: December 21, 2006 http://www.claytonutz.com.au/publications/newsletters/energy_and_resources_insights/20061221/responses_to_wa_domestic_gas_reservation_policy.page

Deloitte (2012); Advancing Australia - Harnessing our comparative energy advantage http://www.deloitte.com/assets/Dcom-Australia/Local%20Assets/Documents/Services/Corporate%20Finance/Access%20Economics/Deloitte_Access_Economics_Advancing_Australia_June_2012.pdf

Dingle, S. (2014): Gas retailers AGL, Origin Energy apply to raise retail prices by 20 per cent in NSW and ACT, February 2014 http://www.abc.net.au/news/2014-02-18/hold-increases-in-retail-gas-prices-looming/5267206

Drummond, M., and Macdonald-Smith, A., (2013) BCA seeks deal on domestic gas supply October 15, 2013 Australian Financial Review, http://www.afr.com/p/australia2-0/bca_seeks_deal_on_domestic_gas_supply_pJpoktttbf43Ev2MkyLZSJ

EIA (2013), "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States", 10th June 2013, US Energy Information Administration, http://www.eia.gov/analysis/studies/worldshalegas/

EnergyQuest (2013) Energy Quarterly Report, November 2013. http://www.energyquest.com.au/reports.php

Energy Quest (2014), Energy Quarterly Report, Feb 2014.
http://www.energyquest.com.au/reports.php

Fullerton (2013); http://www.abc.net.au/news/2013-09-13/fullerton-nt-declares-itself-open-for-business-on-lng/4954038

Government of Western Australia (2013a)
http://www.commerce.wa.gov.au/sites/default/files/atoms/files/localcontentmay2013.pdf

IBIS World, (2011), Queensland Floods: The Economic Impact,
http://www.ibisworld.com.au/common/pdf/QLD%20floods%20special%20report.pdf

IES (2013) Study on the Australian Domestic Gas Market,
http://www.industry.gov.au/Energy/EnergyMarkets/Documents/IESStudyontheAustralianDomesticGasMarket.pdf

IMOWA (2014): Independent Market Operator Western Australia, Gas Statement of Opportunities
http://www.imowa.com.au/docs/default-source/publications-and-reporting/general-documents/gsoo_2_report_final95222D27BB75.pdf?sfvrsn=2 p.120

Kelly, R., (2013), Shell CEO Says Australian LNG Faces Challenges, June 25, 2013,
http://online.wsj.com/article/BT-CO-20130526-701210.html

Ledesma (2013), Oxford Institute for Energy Studies, "East Africa Gas – Potential for Export", David Ledesma NG74, March 2013 - updated: http://www.oxfordenergy.org/2013/03/east-africa-gas-the-potential-for-export/

Macdonald-Smith, A., (2013a), NT keen to plug NSW gas needs September 24, 2013: Australian Financial Review http://m.afr.com/p/australia2-0/nt_keen_to_plug_nsw_gas_needs_EEA5DhjIGWnDvHyE7eG5TK

Macdonald-Smith, A., (2013b), Gas crisis will hit hard: Minister, Australian Financial Review December 16, 2013, http://www.stockandland.com.au/news/agriculture/general/news/gas-crisis-will-hit-hard-minister/2681937.aspx

MacDonald-Smith, A., (2013b), Queensland holds out gas reservation as last resort: Australian Financial Review, April 11, 2013:
http://www.afrsmartinvestor.com.au/p/business/companies/qld_puts_gas_reservation_on_back_bH4Fl8XMadJ3Lk858OgdBP

McAllister, E. (2009) Apache decision on Australia gas, Reuters,
http://www.reuters.com/article/2009/06/04/us-energy-summit-apache-lng-idUSTRE5535LZ20090604

McCullough (2013), Claims that anti-natural gas lobby threatens investment in Australia, Daily Telegraph: May 02, 2013: http://www.dailytelegraph.com.au/business/claims-that-anti-natural-gas-lobby-threatens-investment-in-australia/story-fn7ki14e-1226633356855

Montoya, D. (2012) Coal seam gas royalties in Australian States & Territory, NSW Parliamentary Library Research Service e-brief, January 2012:
http://www.parliament.nsw.gov.au/prod/parlment/publications.nsf/key/CoalseamgasroyaltiesinAustralianStatesTerritories/$File/Coal+seam+gas+royalties+in+Australian+States+&+Territories.pdf

NSW Chief Scientist & Engineer (2013), Initial report on the Independent Review of Coal Seam Gas Activities in NSW, July 2013,
http://www.chiefscientist.nsw.gov.au/__data/assets/pdf_file/0016/31246/130730_1046_CSE-CSG-July-report.pdf

Queensland Legislation (2011) Gas Security Amendment Bill https://www.legislation.qld.gov.au/Bills/53PDF/2011/GasSecurityAB11E.pdf

REMCO (2013): Australian Energy Market Operator and Retail Energy Market Company Limited Business Case for a Short Term Trading Market in Western Australia, http://www.remco.net.au/attachments/article/60/WA%20STTM%20Assessment%20-%20Final%20(26-06-13)%20v6.pdf

Robins B. (2013) AGL profit boosted by price surge, Sydney Morning Herald: August 29, 2013: http://www.smh.com.au/business/agl-profit-boosted-by-price-surge-20130828-2sqtf.html#ixzz2yAX01XOShttp://www.canberratimes.com.au/business/agl-profit-boosted-by-price-surge-20130828-2sqtf.html

Rogers and Stern (2014),'Challenges to JCC Pricing in Asian LNG Markets', Rogers, H and Stern, J , NG 81, OIES 2014, http://www.oxfordenergy.org/2014/02/challenges-to-jcc-pricing-in-asian-lng-markets-2/

Santos (2013); *A Balanced Energy Solution for NSW, April 2013, http://www.santos.com/library/130410_A_balanced_energy_solution_for_NSW.pdf*

Songhurst (2014); Songhurst, B, "LNG Plant Cost Escalation", Working Paper NG-83, Oxford Institute for Energy Studies, Feb 2014. http://www.oxfordenergy.org/2014/02/lng-plant-cost-escalation/

Stewart, P. (2013) Rio Tinto reveals it will close Gove alumina refinery in Northern Territory by July, December 20, 2013: ABC: http://www.abc.net.au/news/2013-12-19/rio-tinto-gove-refinery-to-close-in-july/5167992

Sydney (Platts), 2011, BG's Queensland Curtis LNG project not delayed by recent floods February 1, 2011 http://www.platts.com/latest-news/natural-gas/sydney/bgs-queensland-curtis-lng-project-not-delayed-8481721

University of Western Australia (1991); http://search.uwa.edu.au/search.html?site=search&hl=en&query=search&words=the+economic+impact+of+the+north-west+shelf+project+1991

Unsworth, N. (2010), LNG from CG, Challenges and Opportunities, Foster Wheeler Group at http://www.fwc.com/getmedia/73a219f6-406e-4431-92b8-f5d1843ca946/LNG-from-CSG.pdf.aspx?ext=.pdf

Wood, T., Carter, L., (2013), Getting Gas Right, Grattan Institute Australia's energy challenge, http://grattan.edu.au/static/files/assets/ba24a4e0/189_getting_gas_right_report.pdf

Young (2012), The Performance of Australian Industrial Projects, prepared for the Business Council of Australia by Rob Young, Independent Project Analysis, Inc May 2012 http://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCIQFjAA&url=http%3A%2F%2Fwww.bca.com.au%2Fdocs%2F23453BB8-89E3-42C6-BCB9-9BF49A287C23%2Fthe_peformance_of_australian_industrial_projects_final_7-6-2012.pdf&ei=V_fMU-OFIo-I7Ab034DgBw&usg=AFQjCNEIZEEYNq3CJobkUb32q1GXpknTsw&sig2=LJqf6oY3Pb62fotcBtz9nQ&bvm=bv.71198958,d.ZGU