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Bureau of Resources and Energy Economics

Gas Market Report

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BREE 2014, Gas Market Report 2014, Canberra, November.

ISSN (PDF) 978-1-922106-23-0

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Acknowledgements: BREE would like to thank colleagues in the Department of Industry for comments on papers within this report.

Cover images courtesy of Santos.

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FOREWORD

We are continuing to see a rapid development of gas markets globally in response to strong growth in world energy consumption and the emergence of new gas resources and the technologies to exploit these resources. These developments are driving the recent wave of supply expansion with Australia to become the world's largest LNG supplier by 2018, the United States set to be an LNG exporter and changing patterns of pipeline supply underpinned by growing demand especially in the Asia region. This follows the previous large scale expansions in supply from the Middle East and before that South East Asia and North Africa. These changes in supply are a demonstration of the market dynamics at play in global gas markets.

The scale of the LNG development in Australia is almost without precedent – seven new LNG projects under construction and coming into production over the next four years, an investment worth around $200 billion. This has not been without challenges.

The scale and scope of the projects and their remoteness have contributed to cost pressures for project proponents and the Australian economy more broadly. We would expect to see these cost pressures moderate as the projects come to completion. However, these conditions have focussed attention on the challenges being faced by the LNG industry, particularly the future competitiveness of Australia as an LNG exporter. In addition we have seen new and competing sources of supply enter the market, and the potential for significantly more over the longer term. This expansion in supply is expected to place downward pressure on LNG prices over the medium term, further adding to the pressure on the competitiveness of projects, especially those supplying to the Asia region.

LNG supply from Australia's east coast is supporting the large increase in export capacity available from Australia over this decade. As the east coast domestic gas market transitions to a significant exporter of LNG, the linking to global LNG markets has seen higher prices for domestic consumers. However, these developments will also provide a lasting economic benefit to the Australian economy and in regional Australia.

The 2014 edition of the BREE Gas Market Report provides analysis of the Australian gas industry and its development, projections of future growth in LNG exports, the cost competiveness of Australia's LNG industry and the economic impacts of the CSG development in Queensland.

Wayne Calder

Deputy Executive Director

Bureau of Resources and Energy Economics

November 2014

CONTENTS

ACRONYMS AND ABBREVIATIONS

ABARE	Australian Bureau of Agricultural and Resource Economics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
APPEA	Australian Petroleum Production and Exploration Association
bcf	billion cubic feet
bcm	billion cubic metres
BREE	Bureau of Resources and Energy Economics
CGE	Computable General Equilibrium
COAG	Council of Australian Governments
CSG	coal seam gas
DOE	Department of Energy (United States)
DWGM	Declared Wholesale Gas Market
EIA	Energy Information Administration (United States)
EPBC Act	*Environmental Protection and Biodiversity Conservation Act 1999*
FID	final investment decision
FLNG	floating LNG
FOB	free on board
FPSO	floating production, storage and offtake
FTA	free trade agreement
GDP	Gross Domestic Product
GISERA	Gas Industry Social and Environmental Research Alliance
GJ	gigajoule
GLNG	Gladstone LNG
IEA	International Energy Agency
IMO	Independent Market Operator
JCC	Japan customs-cleared crude/ Japanese crude cocktail
JPDA	Joint Petroleum Development Area (with East Timor)
LPG	liquefied petroleum gas
LNG	liquefied natural gas
LRMC	long run marginal cost
mmbtu	million British thermal units

mmcm	million cubic metres
mmcf	million cubic feet
MPC	marketable petroleum products
Mt	million tonnes
Mtpa	million tonnes per annum
NEB	National Energy Board (Canada)
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NWS	North West Shelf
OECD	Organisation for Economic Co-operation and Development
OPGGS Act	*Offshore Petroleum and Greenhouse Gas Storage Act 2006*
PGPLR	Prospective Gas Production Land Reserve (Queensland)
PJ	petajoule
PRRT	petroleum resource rent tax
QCLNG	Queensland Curtis LNG
QGSO	Queensland Government Statistician's Office
QRC	Queensland Resources Council
SCER	Standing Council on Energy and Resources
SECWA	State Energy Commission of Western Australia
STTM	short term trading market
tcm	trillion cubic metres
TJ	terajoule
tpa	tonnes per annum
USD	US dollars
WGM	World Gas Model (Nexant)

CONVERSION RATES

From	To	mmcm	bcm	tcm	mmcf	bcf	Mt LNG	GJ	TJ	PJ	MMBtu
mmcm	Multiply by:	1	0.001	1.00×10^{-6}	35.31	3.53×10^{-2}	7.35×10^{-4}	38800	38.80	3.88×10^{-2}	36775
bcm		1000	1	1.00×10^{-3}	35313	35.31	0.735	3.88×10^{7}	38800	38.80	3.68×10^{7}
tcm		1.00×10^{6}	1000	1	3.53×10^{7}	35313	735	3.88×10^{10}	3.88×10^{7}	38800	3.68×10^{10}
mmcf		0.028	2.83×10^{-5}	2.83×10^{-8}	1	1.00×10^{-3}	2.08×10^{-5}	1099	1	1.10×10^{-3}	1041
bcf		28.32	0.028	2.83×10^{-5}	1000	1	0.021	1.10×10^{6}	1099	1.099	1.04×10^{6}
Mt LNG		1361	1.361	1.36×10^{-3}	48045	48.04	1	5.28×10^{7}	52787	52.79	5.00×10^{7}
GJ		2.58×10^{-5}	2.58×10^{-8}	2.58×10^{-11}	9.10×10^{-4}	9.10×10^{-7}	1.89×10^{-8}	1	1.00×10^{-3}	1.00×10^{-6}	0.948
TJ		0.026	2.58×10^{-5}	2.58×10^{-8}	0.910	9.10×10^{-4}	1.89×10^{-5}	1000	1	1.00×10^{-3}	948
PJ		25.77	0.026	2.58×10^{-5}	910	0.910	0.019	1.00×10^{6}	1000	1	9.48×10^{5}
MMBtu		2.72×10^{-5}	2.72×10^{-8}	2.72×10^{-11}	9.60×10^{-4}	9.60×10^{-7}	2.00×10^{-8}	1.055	1.06×10^{-3}	1.06×10^{-6}	1

Notes:

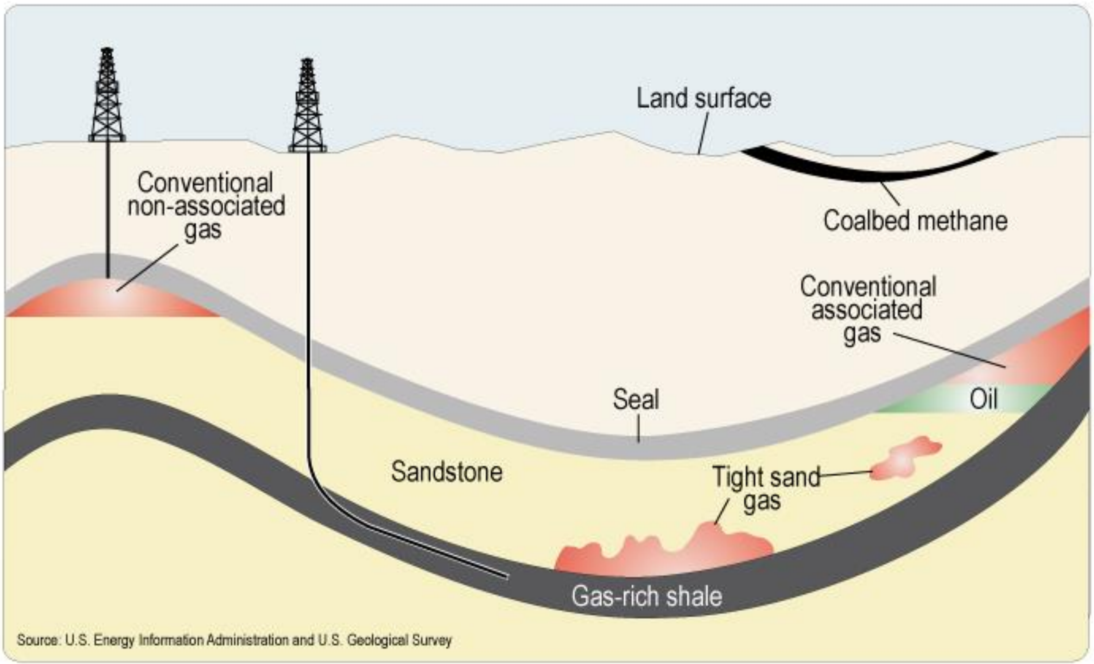
1. To convert 10 million tonnes of LNG into million cubic metres, multiply by 1361—10 million tonnes LNG = 13 610 million cubic metres of gas
2. 1 million cubic metres = 10^{6} x 1.0 cubic metre (m^3)
3. 1 billion cubic metres = 10^{9} x 1.0 cubic metre (m^3)
4. 1 trillion cubic metres = 10^{12} x 1.0 cubic metre (m^3)
5. 1 gigajoule = 10^{9} x 1.0 joule (J)
6. 1 terajoule = 10^{12} x 1.0 joule (J)
7. 1 petajoule = 10^{15} x 1.0 joule (J)
8. 1 British thermal unit = 1055 joules (J)
9. 1 tonne = 10^{3} x 1.0 kilogram (kg) = 2205 pounds (lbs)

1 AN OVERVIEW OF AUSTRALIA'S NATURAL GAS RESOUCES AND MARKETS

Australia's natural gas resources

Australia's natural gas resources are substantial and comprise gas from both conventional and unconventional sources. Conventional gas is extracted from porous rock formations such as sandstones and may be associated with oil reserves. Unconventional gas is extracted from coal seams around 300–1000 metres underground (coal seam gas (CSG), also referred to as coal-bed methane), rock formations with very low permeability at depths greater than 1000 metres (tight gas), and low permeability sedimentary rock at 1000 to over 2000 metres underground (shale gas). Figure 1.1 provides a cross section schematic that illustrates the differences between the various types of natural gas in terms of the relative depths at which they occur and the geological features.

Figure 1.1 Schematic of conventional and unconventional natural gas

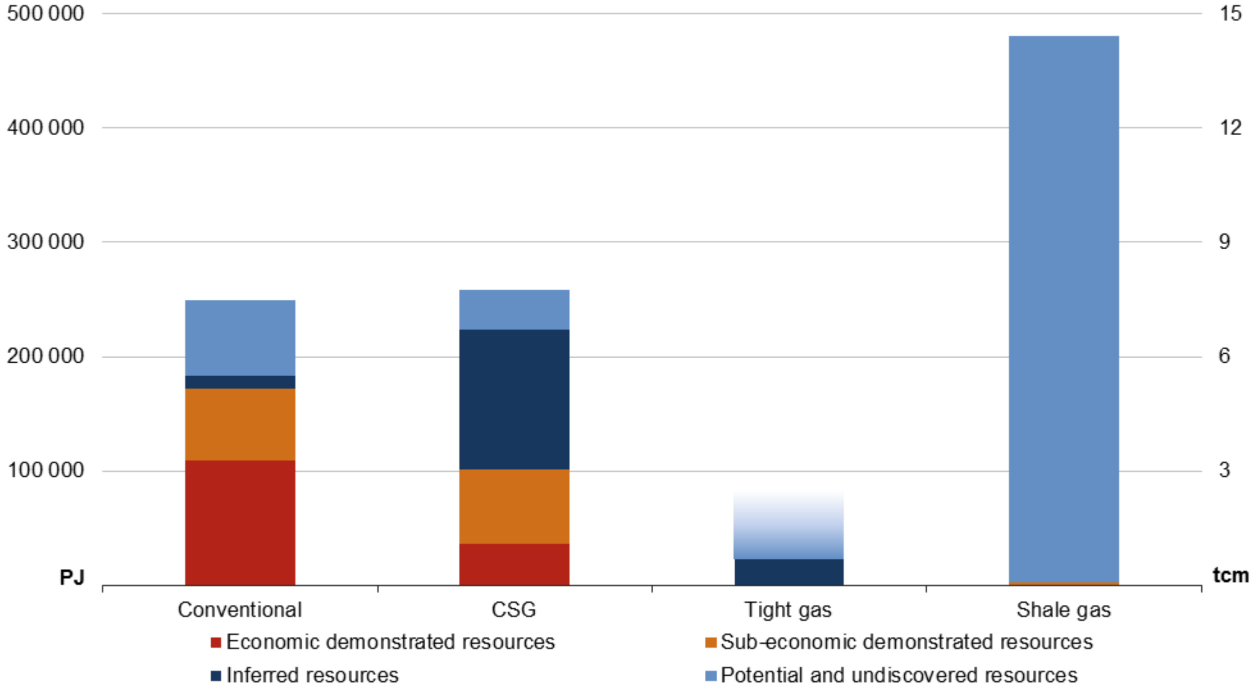


Source: US Energy Information Administration (2011).

Natural gas is Australia's third largest energy resource after coal and uranium. Australia has significant identified, potential and undiscovered conventional resources of around 249 700 petajoules (PJ) and unconventional resources of around 761 640 PJ, with the latter consisting of CSG, tight gas and shale gas (Geoscience Australia and BREE 2014).

Although Australia's estimated unconventional gas resource is large, further work is required to confirm the resource and assess many basins that have yet to be explored. Figure 1.2 illustrates the in-ground potential of different gas resources from the most recent *Australian Energy Resource Assessment*.

Figure 1.2 Australia's conventional and unconventional gas resources



Note: Potential tight gas resources are unknown.
Source: Geoscience Australia & BREE (2014), AERA: p97.

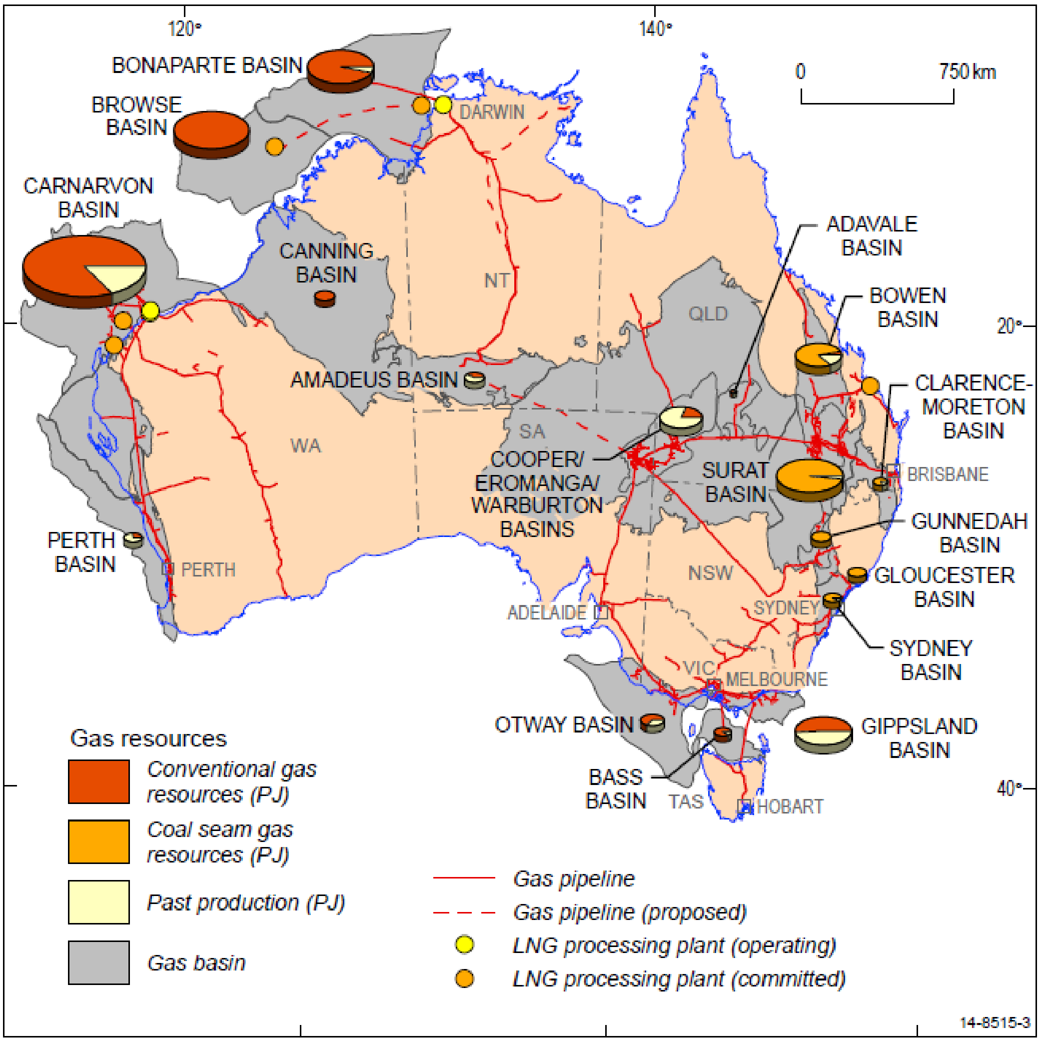
Conventional gas

About 92 per cent of Australia's identified conventional gas resource, equivalent to just over half of Australia's natural gas, is located offshore along the north-west coast in the Carnarvon, Browse and Bonaparte basins (figure 1.3) (Geoscience Australia and BREE 2014).[1]

Some of the geologically youngest conventional petroleum reservoirs are situated in the offshore Gippsland, Bass and Otway basins in the south-east. Some of the geologically oldest conventional reservoirs are in the Cooper Basin in central Australia spanning South Australia and Queensland, and the Amadeus Basin spaning Western Australia and the Northern Territory. Some of these basins such as the Cooper, Otway and Amadeus are at various stages of advanced depletion.

[1] Refer to Boreham et al. (2001) for a detailed discussion on the geology and geography of Australia's conventional gas resources.

Figure 1.3 Australia's major gas resources and infrastructure



Source: Geoscience Australia.

Coal seam gas

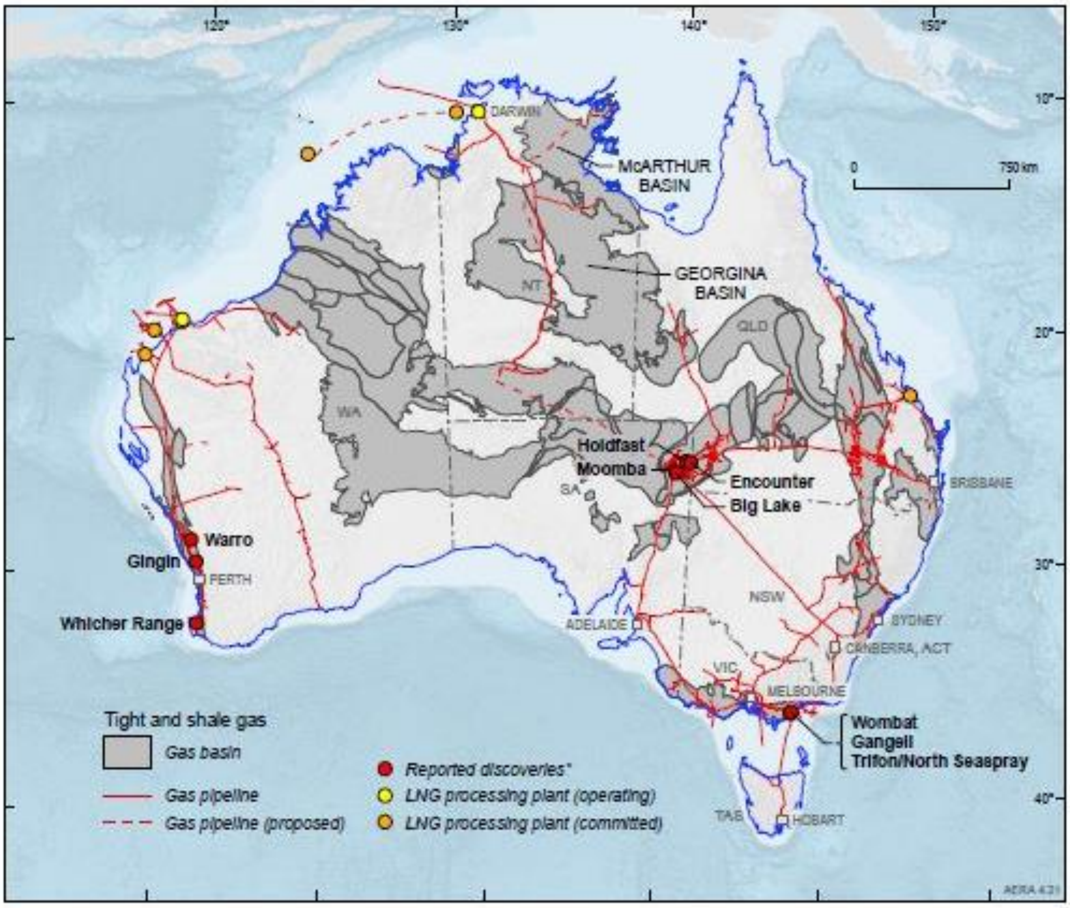
As illustrated in figure 1.3, Australia's CSG resources are mostly located along the east coast of Australia, in Queensland's Bowen and Surat basins, and the Gunnedah, Gloucester, Clarence Morton and Sydney basins in New South Wales. Gas production from coal seams grew rapidly during the 2000s and now accounts for around 12 per cent of Australia's total gas production. In Queensland, it accounts for 89 per cent of gas production. This rapid growth in exploitation of Queensland's CSG resources over the last decade has occurred due to greater knowledge about the scale of the resource, a supportive policy environment and opportunities to increase its economic value as an energy source for electricity generation and feed-stock for LNG production. CSG reserves in New South Wales and Victoria are considerably smaller than those in Queensland, but still represent significant potential sources of new supply.

Tight and shale gas

Tight gas is not commercially produced in Australia. However, large resources are located in existing conventional reservoirs in Western Australia (Perth Basin), South Australia (Cooper Basin) and Victoria (Gippsland Basin). These resources are all relatively close to existing transportation and processing infrastructure, and thereby possess the most potential for commercialisation (figure 1.4).

Australia's estimated shale gas resource is almost twice the size of conventional gas resources and almost equivalent to the resource estimate for all other sources of gas combined. Shale gas resources are located in remote basins in Western Australia, Queensland, the Northern Territory and South Australia, and in the less remote Sydney and Bowen basins in New South Wales and Queensland, respectively. Shale gas exploration and development is mainly occurring in the Cooper Basin in South Australia and Queensland, and the Canning Basin in Western Australia. The Cooper Basin benefits from being close to existing infrastructure used for conventional gas and oil production and, therefore, is likely to experience the most rapid development of its shale gas resource if it proves economically viable.

Figure 1.4 Australia's tight and shale gas resources



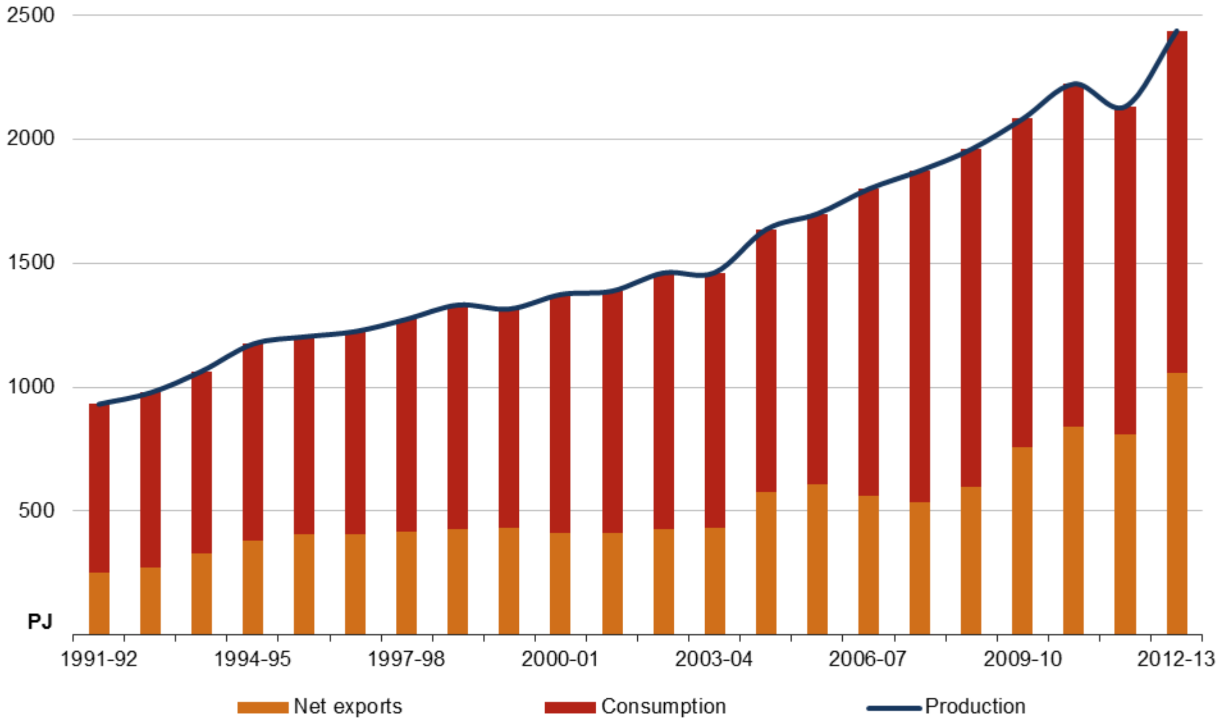
Source: Geoscience Australia and BREE (2014): p.99.

Production and use

Gas production

Australia's natural gas production has been growing at an average annual rate of 4.5 per cent over the past two decades (figure 1.5). The 2439 PJ produced in 2012-13 represents an increase of just over two and a half times the 1991-92 quantity of 932 PJ. The increase in production over that period has been in response to growing domestic demand (3.3 per cent a year since 1991-92), and LNG export demand (6.7 per cent a year since 1991-92).

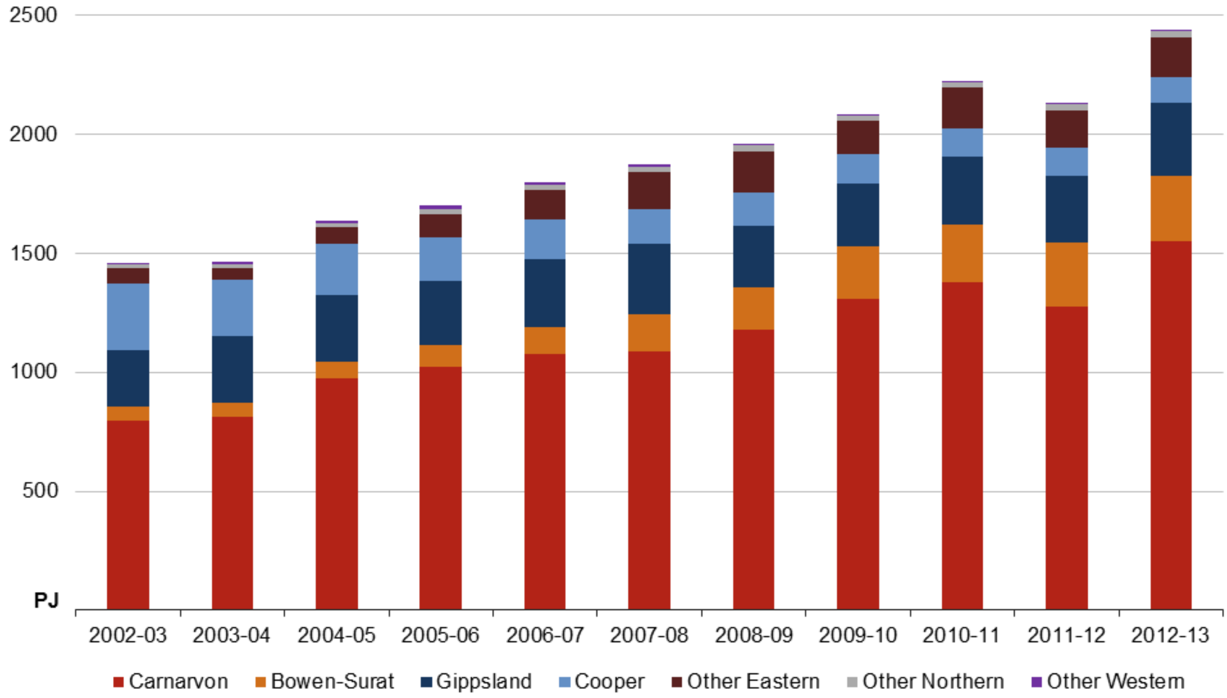
Figure 1.5 Australia's gas balance



Note: Consumption includes statistical discrepancies. Net exports account for gas produced and imported from the Joint Petroleum Development Area in the Timor Sea whic is liquefied and exported from Darwin LNG.
Source: BREE (2014), Australian Energy Statistics.

As shown in figure 1.6, approximately 64 per cent of Australia's gas was produced from the Carnarvon Basin in Western Australia in 2012-13. This compares with 13 per cent from the Gippsland Basin and 11 per cent from the Bowen-Surat basins in the same year. Production from the Carnarvon Basin has undergone the most dramatic growth over the 11 years up to 2012-13, doubling from 799 PJ to 1599 PJ. The Cooper Basin had the most significant decline in production, with output falling from 279 PJ in 2002-03 to 108 PJ in 2012-13. This decline represents a reduction in the Cooper's share of Australia's total gas production from 19 per cent to 4 per cent over that period. An increase in gas production from the Bowen-Surat basins from 56 PJ in 2002-03 to 276 PJ in 2012-13, together with increased production from other smaller eastern market gas basins (such as Otway, Bass and Sydney), has more than offset the decline in production from the Cooper since 2002-03.

Figure 1.6 Gas production by basin

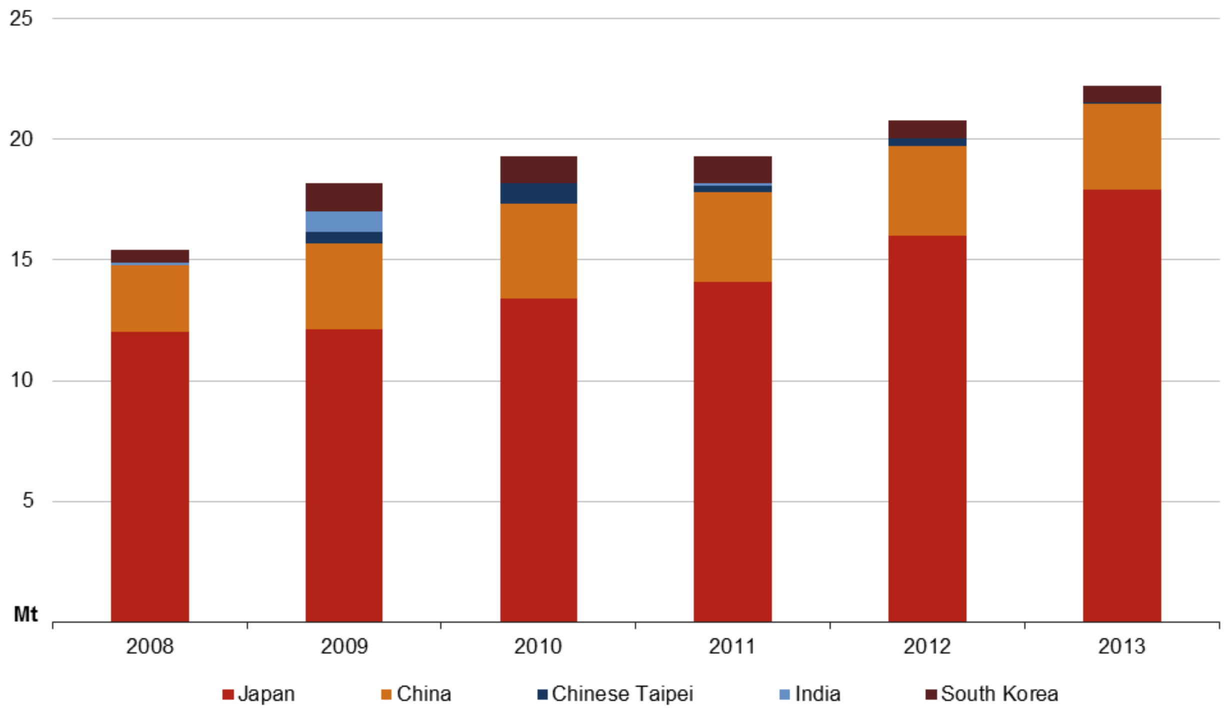


Source: BREE (2014), Australian Energy Statistics.

LNG exports

Australian LNG exports commenced in 1989 from the North West Shelf venture based on long-term contracts with the Japanese market, which is still the dominant importer of Australian LNG. However, LNG exports have expanded over time with a number of other countries becoming important destinations for Australian LNG exports. Over the period 2008 to 2013, Australia exported gas to five countries in the Asia region: Chinese Taipei, India, China, South Korea and Japan (figure 1.7). Of the 22.2 million tonnes of LNG exported in 2013, 81 per cent (17.9 million tonnes) was delivered to Japan and 16 per cent (3.6 million tonnes) was delivered to China. The 6.8 per cent growth in total exports over the six years was mostly due to increased demand from Japan following the Fukushima disaster. Exports of LNG to Japan increased at an average rate of 7 per cent each year over the period.

Figure 1.7 Australia's LNG exports by destination

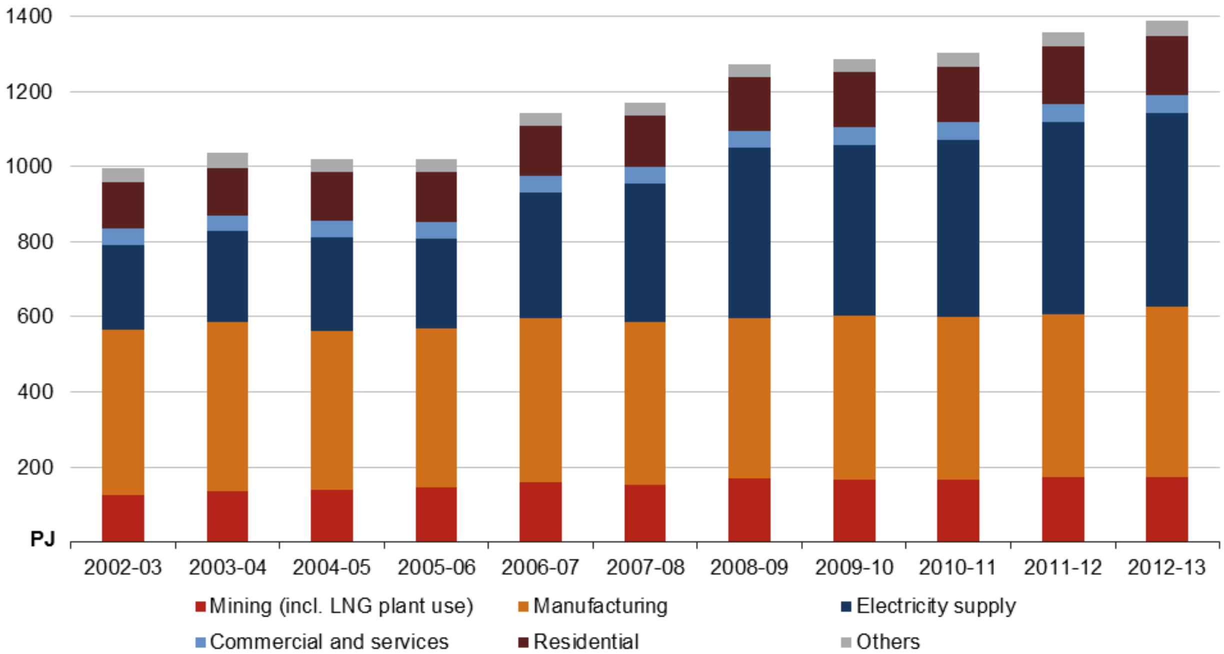


Source: BREE.

Domestic gas use

From 2002-03 to 2012-13, gas use in Australia grew from 997 PJ to 1387 PJ, which is an average annual growth rate of just over 3 per cent (figure 1.8).

Figure 1.8 Australia's gas use by sector



Source: BREE, Australian Energy Statistics 2014.

In 2012-13, 517 PJ of gas was used in the electricity generation sector. The sector grew at an average annual rate of just under 8 per cent and was responsible for around 75 per cent of total growth over the eleven years. Growth in the use of gas in electricity generation increased between 2005-06 and 2012-13, to just over 10 per cent, reflecting the impact of national and state based policies favouring gas use in electricity generation during that period.

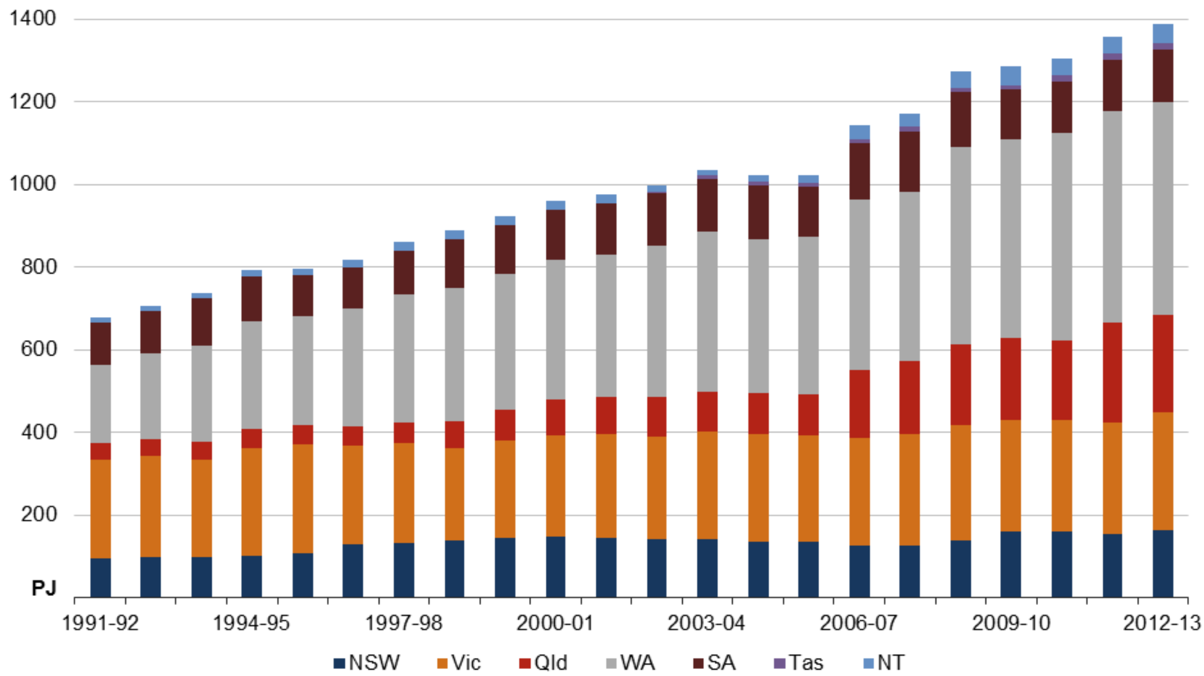
For the period of 2002-03 to 2012-13, the mining sector had the next highest average annual growth rate at 3 per cent, and accounted for around 13 per cent of total growth. This was due to increased demand associated with strong mining growth and expansion of LNG liquefaction capacity. The sector used 175 PJ of gas in 2012-13.

The remaining growth in gas use was attributed to the residential (2 per cent), commercial (just under 1 per cent) and manufacturing sectors (0.2 per cent). Although growth in gas use in the manufacturing sector was negligible, within the sector the chemicals sub-sector had an average annual growth rate of 1.6 per cent, while the metals sub-sector reduced its average annual gas use at a rate of 0.7 per cent.

In 2012-13, 451 PJ of gas was used in manufacturing, 155 PJ by the residential sector and 48 PJ by the commercial sector.

Breaking down domestic gas use by state highlights the contribution that Queensland has made to growth in Australia's overall gas use (figure 1.9). Over the period 1991-92 to 2012-13, while Australia's gas use increased at an average annual rate just over 3 per cent, Queensland's use grew at a rate of more than 8 per cent a year.

Figure 1.9 Australia's gas use by state

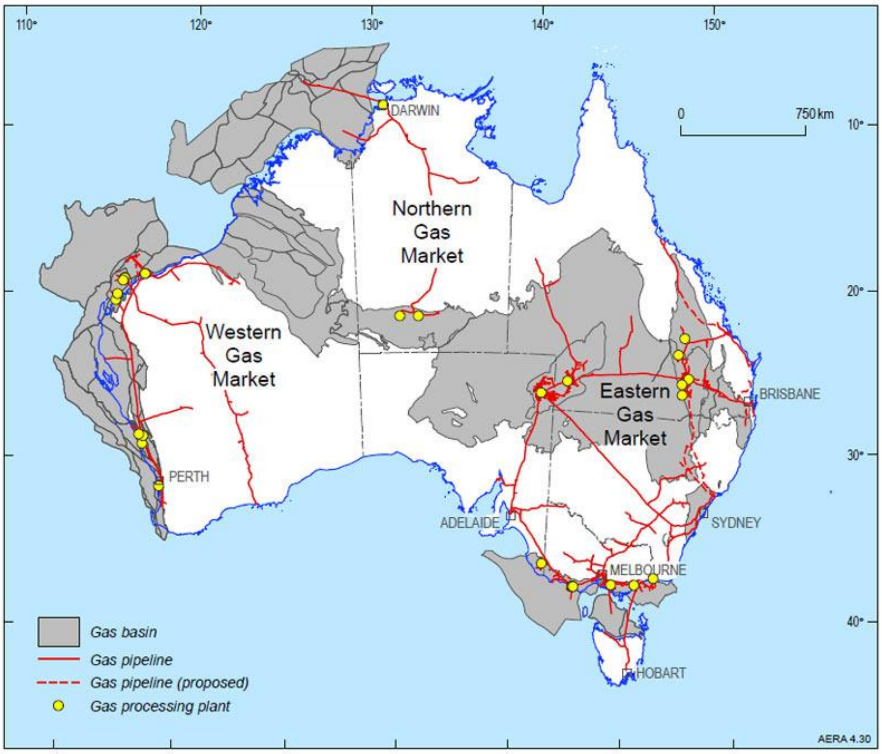


Source: BREE, Australian Energy Statistics 2014.

Australia’s natural gas markets

Australia has three distinct and physically separated domestic gas markets: the western market in Western Australia, the northern market in the Northern Territory and the eastern market linking the states of South Australia, Victoria, New South Wales, Queensland and Tasmania (figure 1.10).

Figure 1.10 Australia's gas markets and infrastructure

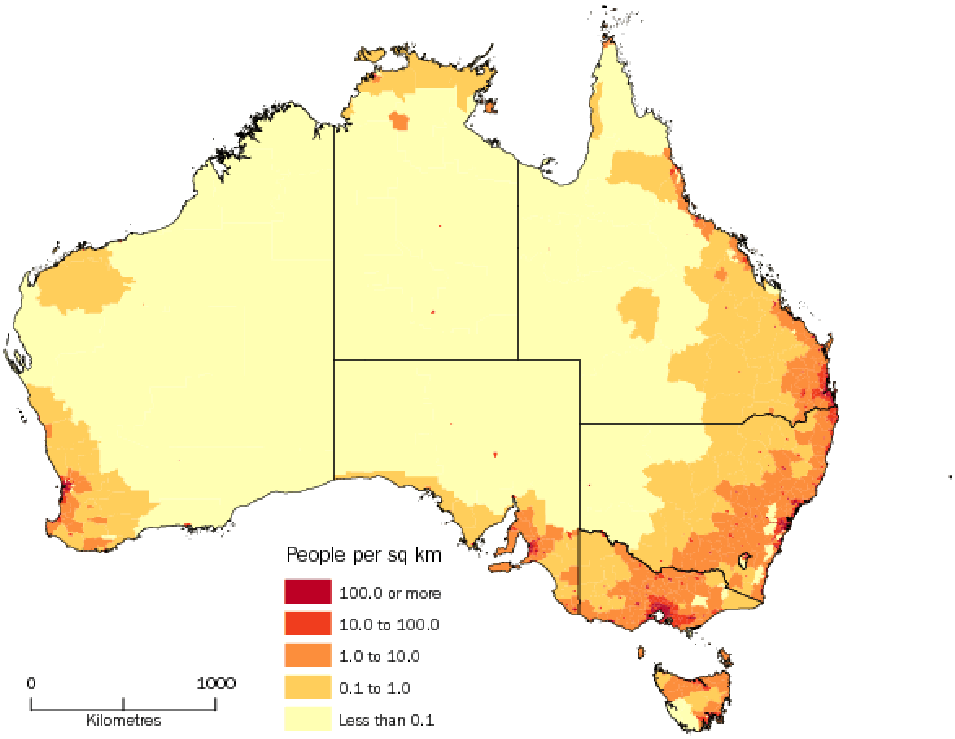


Source: Geoscience Australia (2014a)

The development of each of the gas markets has been strongly influenced by three characteristics:

- The remoteness of most of the gas supply basins from major population centres and the distance between the population centres (figure 1.11)
- Energy demand concentrated in and around widely dispersed population centres
- Low domestic gas demand compared to many other countries due to a relatively small population, relatively small manufacturing sector, a temperate climate, and electricity generation based largely on coal

Figure 1.11 Australia's population density, June 2013



Source: ABS (n.d.b).

In terms of distinctiveness, the eastern gas market has the largest population and a large proportion of Australia's manufacturing activity, which are mostly concentrated in several major demand centres along the coast. It also has a more variable climate and, hence, greater seasonality in demand. Unlike the western and northern markets, coal-fired electricity plants provide the largest share of the eastern market's generation capacity. While all three markets provide gas to the mining sector, this sector is significant in terms of its share and volume in the northern and western markets.

Currently, only the western and northern gas markets have operating LNG export facilities with a combined capacity of 24.3 Mtpa (with another 36.5 Mtpa under construction). LNG production in the eastern market will commence over the coming year with plants totalling 25.3 Mtpa of capacity under construction on Curtis Island in Queensland. By 2020 when these plants are fully operational the Western market will have 53 per cent of Australia's total export liquefaction capacity, followed by the eastern market with 29 per cent and the Northern market with 14 per cent

Table 1.1 presents a range of characteristics relating to the three gas markets, which highlight each market's distinctiveness.

Table 1.1 Characteristics of Australia's gas markets

	Western Australia	Northern Territory	Eastern Gas Market
Mainland Area (sq km)[1]	2 526 786	1 335 742	3 797 333
Population[2]	2 565 600	243 700	20 613 300
Gas production (PJ), 2012–13	1551	26	854
Gas consumption (PJ), 2012-13	516	45	826
Gas exports (PJ), 2012–13	1063	214	0
Major sector users	LNG exports, Electricity generation, Manufacturing,	LNG exports, Electricity generation,	Manufacturing, Electricity generation
Major operating pipelines[3,4,5]	7	2	16
Major pipeline length (km)[3,4,5]	5032	2678	9192
Storage facilities	2	0	7
LNG export plants – operating	2 (20.6 Mtpa)	1 (3.7 Mtpa)	
LNG export plants – under construction	3 (28.1 Mtpa)	1 (8.4 Mtpa)	3 (25.3 Mtpa)
Balancing / short term trading markets	None	None	Declared Wholesale Market (Vic); Short Term Trading Markets (Adelaide, Brisbane, Sydney); Supply Hub (Wallumbilla, Qld)

[1] Geoscience Australia (2014b).

[2] ABS (n.d.a).

[3] IMO (2014).

[4] AEMO (2014).

[5] Northern Territory Government Department of Mines and Energy (n.d.).

Eastern gas market

The eastern market is the largest 'domestic' gas market and is currently undergoing a major transition as the LNG export projects in Queensland begin production. The first of the three LNG projects, Queensland Curtis LNG (QCLNG) is expected to begin production in late 2014. Demand in the eastern market is shifting from being driven solely by domestic consumption (mainly large industrial, commercial, electricity generation and residential) to a market that will become increasingly dominated by LNG exports. Over the next five years, supply in the eastern market is projected to increase to 2392 PJ when the LNG liquefaction plants with a combined capacity of 25.3 Mtpa are fully operating (table 1.2).

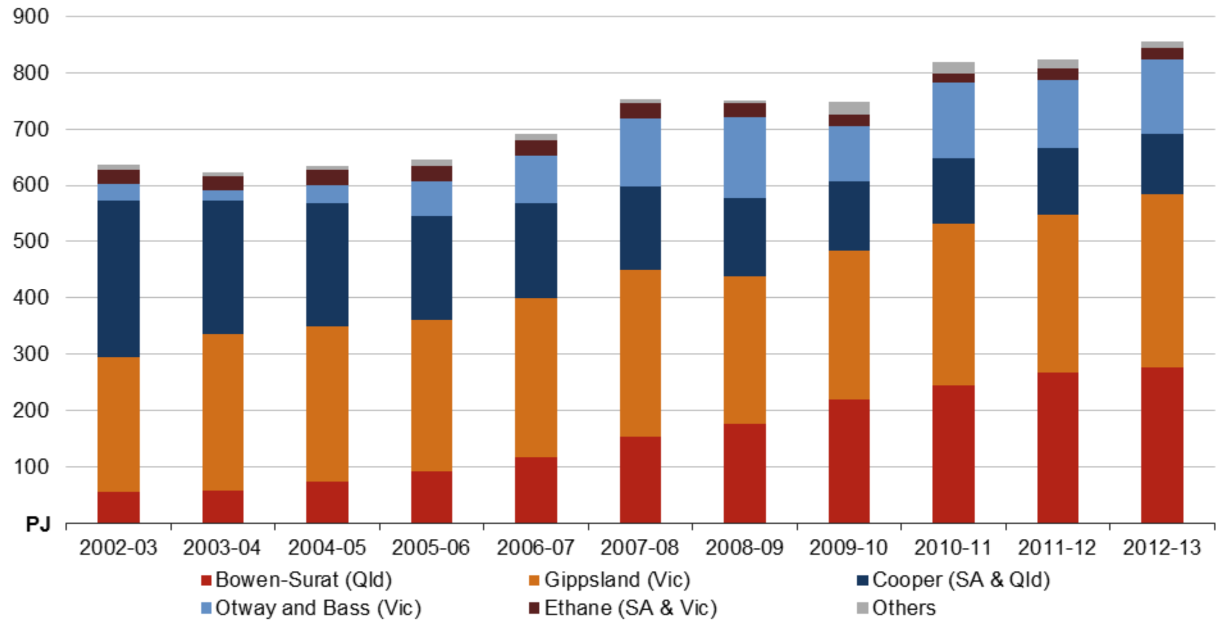
Table 1.2 LNG projects under construction – eastern market

Committed Project	Ownership	Share	Operator	Nameplate Capacity	Train/ Capacity	Actual / expected operating date	Location: Basin LNG Plant
Australian Pacific LNG (APLNG) (coal seam gas)	Origin	37.5%	Conoco-Phillips	9.0 Mtpa	Train 1 – 4.5 Mtpa	H2 2015	Surat-Bowen Gladstone Queensland
	ConocoPhillips	37.5%					
	Sinpoec	25%			Train 2 – 4.5 Mtpa	H1 2016	
Gladstone LNG (GLNG) (coal seam gas)	Santos	30%	Santos	7.8 Mtpa	Train 1 – 3.9 Mtpa	H1 2015	Surat-Bowen Gladstone Queensland
	Petronas	27.5%					
	Total	27.5%			Train 2 – 3.9 Mtpa	H2 2015	
	Kogas	15%					
Queensland Curtis LNG (QCLNG) (coal seam gas)	BG	73.75%	BG	8.5 Mtpa	Train 1 – 4.25 Mtpa	H2 2014	Surat-Bowen Gladstone Queensland
	CNOOC	25%					
	Tokyo Gas	1.25%			Train 2 – 4.25 Mtpa	H2 2015	

Source: BREE and company reports.

The eastern market is mainly supplied by conventional gas from Victoria's Gippsland and Otway basins, the Cooper and Eromanga basins in inland South Australia and Queensland and from CSG fields predominantly located in the Bowen and Surat basins (figure 1.12).

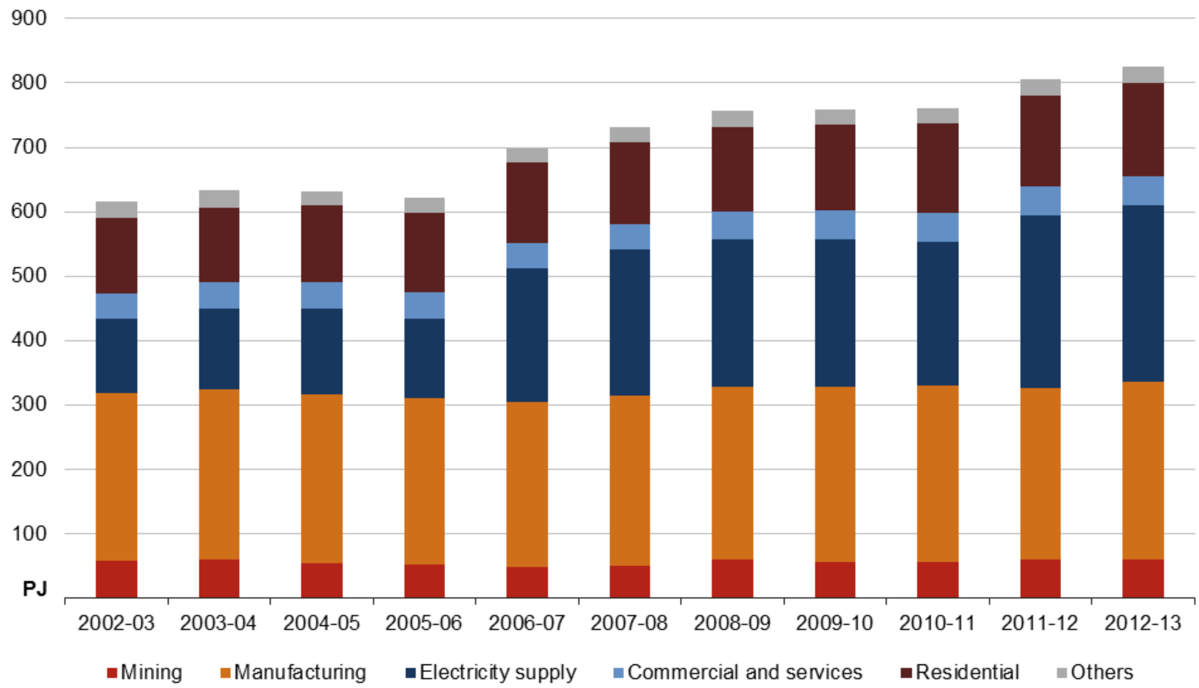
Figure 1.12 Gas production in the eastern market



Source: BREE (2014), Australian Energy Statistics.

Figure 1.13 presents the sectoral composition of gas use in the eastern market over the 11 years to 2012-13. In 2012-13, 826 PJ of gas was used. The largest share was in the manufacturing sector with 34 per cent (277 PJ), followed by electricity generation with 33 per cent (274 PJ), residential with 17 per cent (145 PJ) and mining with 7 per cent (59 PJ). Over the eleven years to 2012-13, total gas use grew at an average 2.7 per cent each year. Gas use in electricity generation had by far the highest average yearly growth rate at 8.3 per cent, followed by the residential sector with an average yearly growth rate of 2 per cent.

Figure 1.13 Gas use in the eastern market



Source: BREE (2014), Australian Energy Statistics.

The eastern market has the greatest range of large industrial users compared to the other two markets. Activities include:

- smelters (mainly alumina)
- fertilisers, chemicals and plastics production
- mineral, petroleum and coke refining
- glass and cement production
- steelworks
- electricity generation

In the lead up to LNG production, a key issue in the eastern market is the performance of CSG wells and, hence, the number of wells required for production to meet gas demand from LNG plants. This has resulted in some concern about the capacity of the eastern market to supply sufficient volumes of gas to domestic users in the absence of significant new supply (IEA 2014).

In January 2014, the Australian Government responded to rising uncertainty about both the availability and cost of domestic gas in the eastern market in its *Eastern Australia Domestic Gas Market Study* (Department of Industry and BREE 2014). The study considered the eastern market's transition to linking to the LNG export market and identified six policy option themes that could assist the market in efficiently transitioning to a larger and more dynamic market:

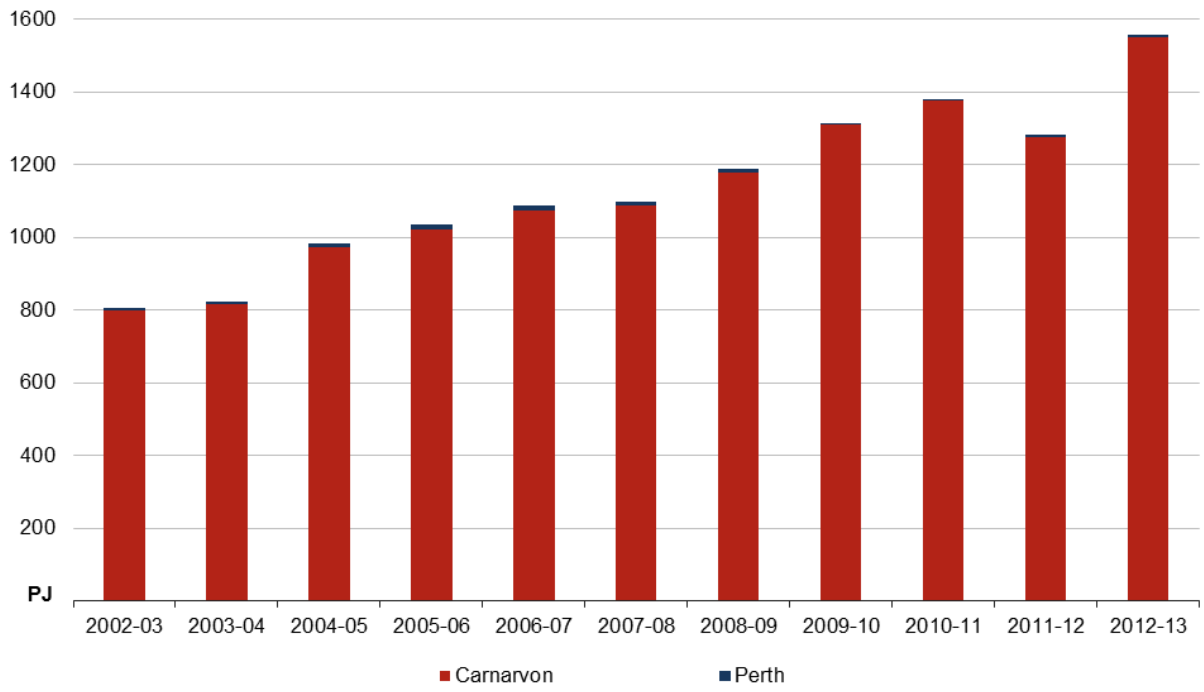
- Gas market reform
- Gas supply competition
- Commercial and regulatory environment for infrastructure

- Data and transparency
- Non-market interventions
- Governance and implementation

Western gas market

The western market is Australia's largest gas producing market and is supplied mostly from the conventional offshore Carnarvon Basin in the State's north-west (a small amount of gas is also produced in the Perth Basin). Figure 1.14 shows the amount of gas produced from the two basins from 2002-03 to 2012-13. The Carnarvon Basin is the home of two of Australia's three operating LNG plants (North West Shelf and Pluto LNG) and is connected to the main non-mining demand centres in the south-west via the Dampier to Bunbury pipeline.

Figure 1.14 Gas production in the western market



Source: BREE (2014), Australian Energy Statistics.

The western market has 20.6 Mtpa (about 85 per cent) of Australia's total 24.3 Mtpa operating LNG capacity (table 1.3). Another 28.1 Mtpa of capacity is currently under construction, which includes Prelude – the world's largest floating liquefied natural gas plant (table 1.4).

Total gas demand of 1551 PJ in 2012-13 is projected to increase to 2860 PJ in 2018-19 primarily due to increases in LNG exports.

Table 1.3 LNG projects operating – western market

Operating Project	Ownership	Share	Operator	Nameplate Capacity	Train/Capacity/First Gas	Location: Basin LNG Plant
North West Shelf Venture	BHP Billiton Petroleum (North West Shelf) Pty Ltd	16.67%	Woodside Energy Ltd	16.3 Mtpa	Train 1 – 2.5 Mtpa 1989	Carnarvon Karratha
	BP Developments Australia Pty Ltd	16.67%			Train 2 – 2.5 Mtpa 1989	
	Chevron Australia Pty Ltd	16.67%			Train 3 – 2.5 Mtpa 1992	
	Japan Australia LNG (MIMI) Pty Ltd	16.67%			Train 4 – 4.4 Mtpa 2004	
	Shell Development (Australia) Pty Ltd	16.67%			Train 5 – 4.4 Mtpa 2008	
	Woodside Energy Ltd	16.67%				
Pluto Project	Woodside Energy Ltd	90%	Woodside Energy Ltd	4.3 Mtpa	Train 1 – 4.3 Mtpa 2012–13	Carnarvon Karratha
	Tokyo Gas	5%				
	Kansai Electric	5%				

Source: BREE and company reports.

Table 1.4 LNG projects under construction – western market

Committed Project	Ownership	Share	Operator	Nameplate Capacity	Train/ Capacity	Actual / expected operating date	Location: Basin LNG Plant
Gorgon LNG/DomGas	Chevron	47%	Chevron	15.6 Mtpa	Train 1 – 5.2 Mtpa	H1 2015	Carnarvon Barrow Island
	ExxonMobil	25%			Train 2 – 5.2 Mtpa	H2 2015	
	Shell	25%			Train 3 – 5.2 Mtpa	H1 2016	
	Osaka Gas	1.25%					
	Tokyo Gas	1%					
	Chubu Electric Power	0.42%					
Wheatstone LNG/DomGas	Chevron	64.14%	Chevron	8.9 Mtpa	Train 1 – 4.45 Mtpa	H2 2016	Western Australia Carnarvon Onslow
	APACHE	13%			Train 2 – 4.45 Mtpa	H1 2017	
	KUFPEC	7%					
	Shell	6.4%					
	Kyushu Electric Power Company	1.46%					
	PE Wheatstone Pty Ltd	8%					
Prelude LNG/Condensate/ LPG	Shell	67.5%	Shell	3.6 Mtpa	Train 1 – 3.6 Mtpa	H2 2017	Browse FLNG*
	INPEX	17.5%					
	Kogas	10%					
	CPC	5%					

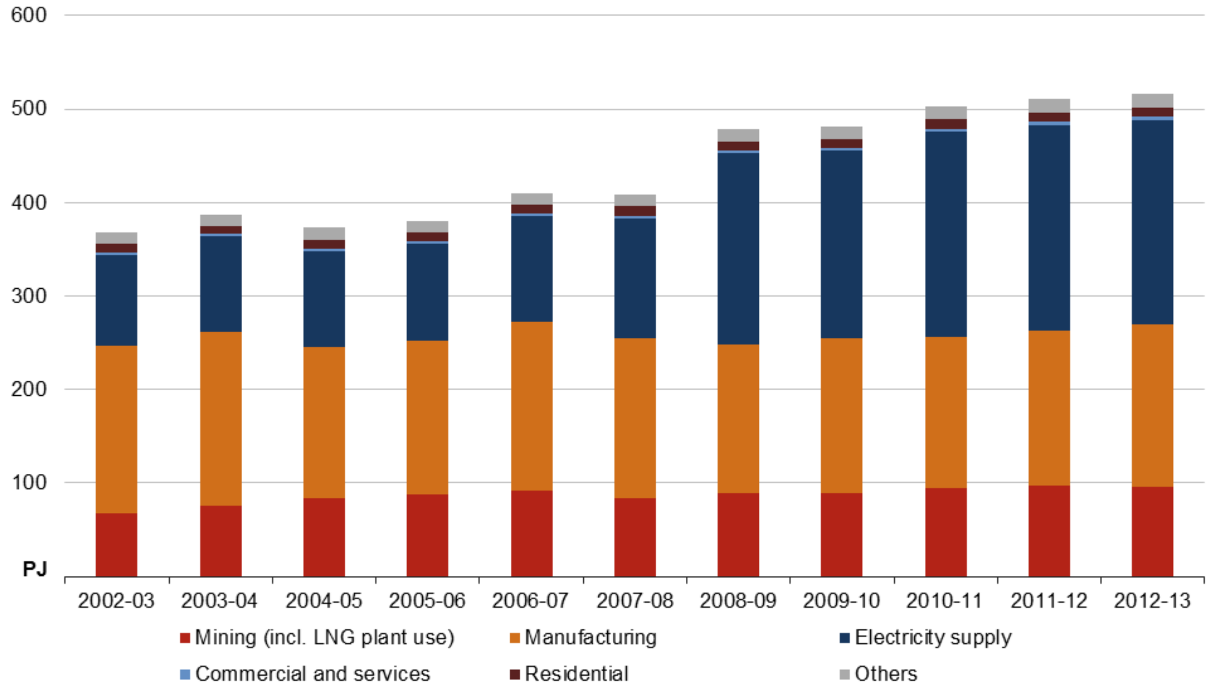
Source: BREE and company reports.

*FLNG – floating liquid natural gas

Figure 1.15 presents the sectoral composition of domestic gas use in the western market over the 11 years to 2012-13. In 2012-13, the largest share of gas use was in electricity generation at 42 per cent, followed by manufacturing (34 per cent), mining (19 per cent), other (3 per cent) and residential (2 per cent). Over the eleven years to 2012-13, average annual total gas use grew at 3.1 per cent. Gas use in electricity generation had by far the highest yearly growth rate at 8.3 per cent, followed by the residential sector at 2 per cent.

In 2012-13, 516 PJ of gas was consumed for domestic purposes. The majority of domestic gas consumption in 2012-13 was in the electricity generation (218 PJ), followed by manufacturing (174 PJ) and mining sectors (96 PJ). This gas was mainly sourced from the Carnarvon Basin.

Figure 1.15 Gas use in the western market



Source: BREE (2014), Australian Energy Statistics.

The main large industrial gas uses in the western market relate to the activities of:

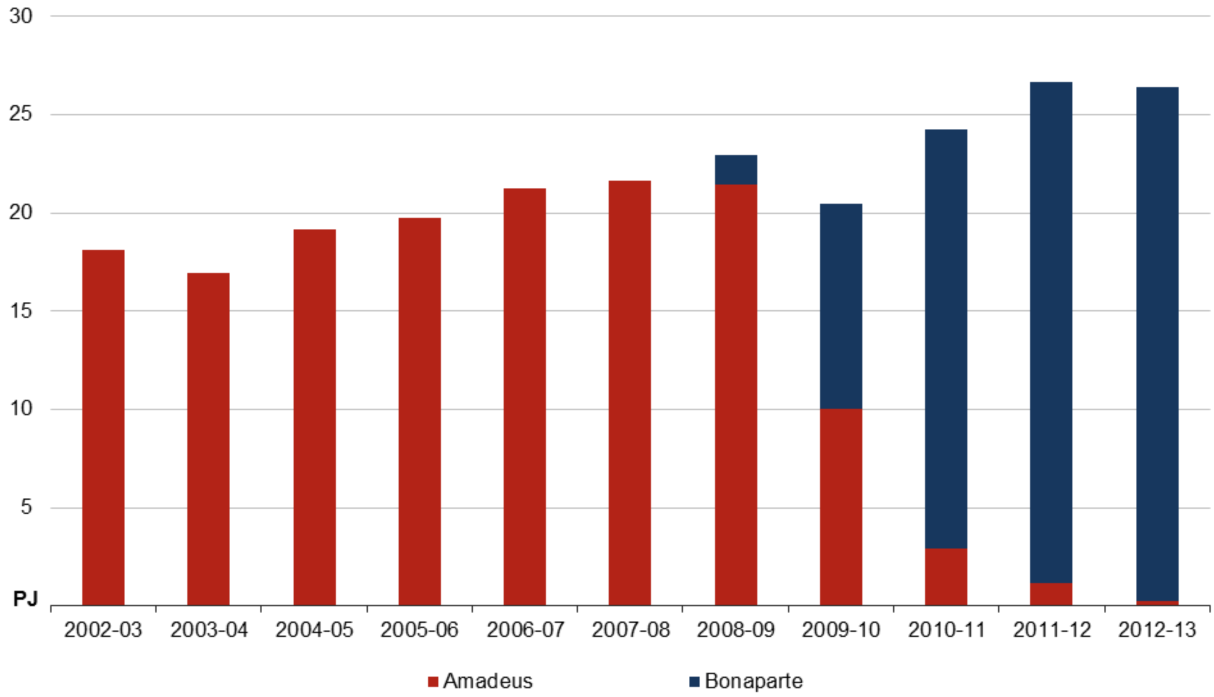
- alumina smelting
- fertiliser production
- refining and mining operations
- electricity generation

The western market is the only market that has a gas reservation policy in effect for gas export projects. The *Policy on Securing Domestic Gas Supplies* requires proponents of gas export projects to make available to the domestic market up to an equivalent of 15 per cent of their LNG production at commercial rates (Parliament of Western Australia 2014).

Northern gas market

The northern market is the smallest of the three markets at about 26 PJ produced in 2012-13, but production is projected to increase to 667 PJ in 2018-19.[2] In 2012-13, most gas was sourced from the Bonaparte Basin via the Blacktip field (figure 1.16). Up to 2007-08, gas from the Amadeus Basin wholly supplied the market. Since then the Amadeus has been progressively depleting and in 2012-13 supplied less than 1 per cent of the northern market.

Figure 1.16 Gas production in the northern market

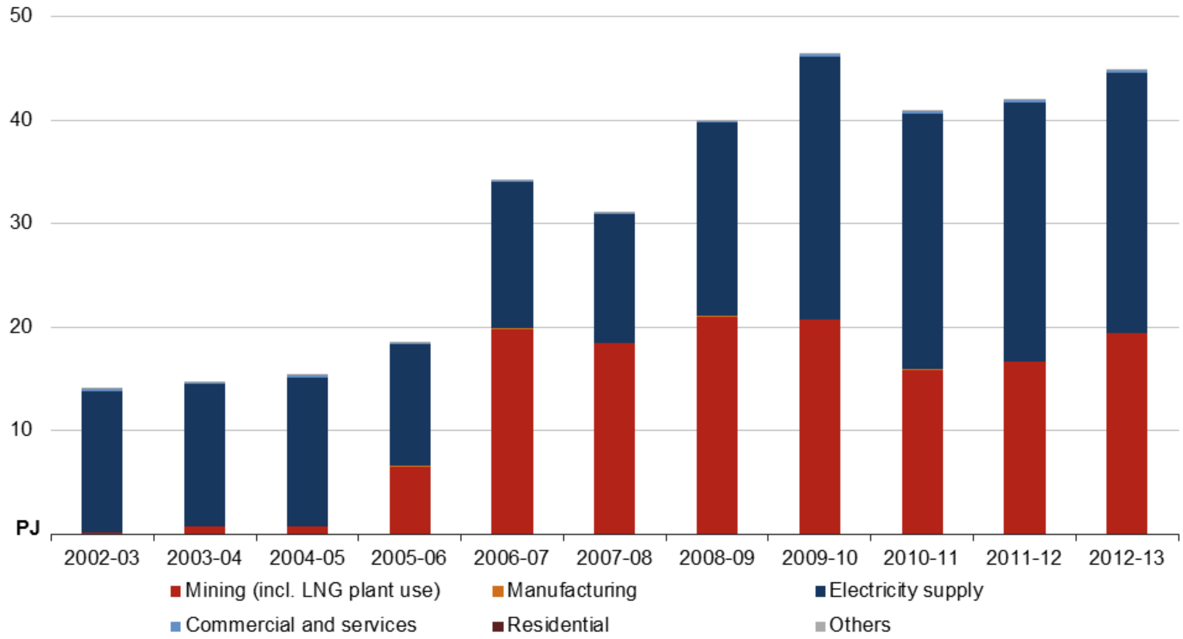


Source: BREE (2014), Australian Energy Statistics.

In 2012-13, domestic gas use in the northern market was 45 PJ and underpinned by large industrial mining (which mostly consist of gas used at the Darwin LNG plant), and electricity generation) (figure 1.17). These two sectors accounted for 43 per cent (19 PJ) and 56 per cent (25 PJ) of total gas use in 2012-13, respectively. Gas use in electricity generation has grown strongly over the 11 years to 2012-13, averaging 5.7 per cent a year. There are currently feasibility studies being undertaken on proposals for pipeline options linking the northern gas market to the eastern gas market, either through Queensland or South Australia (APA Group 2014).

[2] Gas production associated with Darwin LNG comes from the Joint Petroleum Development Area (JPDA) in the Timor Sea. For energy accounting purposes, all the gas produced at the JPDA is considered an import into Australia, and is not included in northern market production.

Figure 1.17 Gas use in the northern market



Source: BREE (2014), Australian Energy Statistics.

The northern market has one of the three currently operating LNG plants which accounts for just over 15 per cent of Australia's current LNG production capacity (Darwin LNG; table 1.5). By the end of 2017, LNG production capacity is scheduled to expand by another 8.4 Mtpa with start of both trains of the Ichthys LNG project (table 1.6).

Table 1.5 LNG projects operating – northern market

Operating Project	Ownership	Share	Operator	Nameplate Capacity	Train/Capacity/First Gas	Location: Basin LNG Plant
Darwin LNG	ConocoPhillips	56.72%	ConocoPhillips	3.7 Mtpa	Train 1 – 3.7 Mtpa 2006	JPDA Bayu-Undan Darwin
	ENI	12.04%				
	Santos	10.64%				
	INPEX	10.53%				
	TEPCO	6.72%				
	Tokyo Gas	3.36%				

Source: BREE and company reports.

Table 1.6 LNG projects under construction – northern market

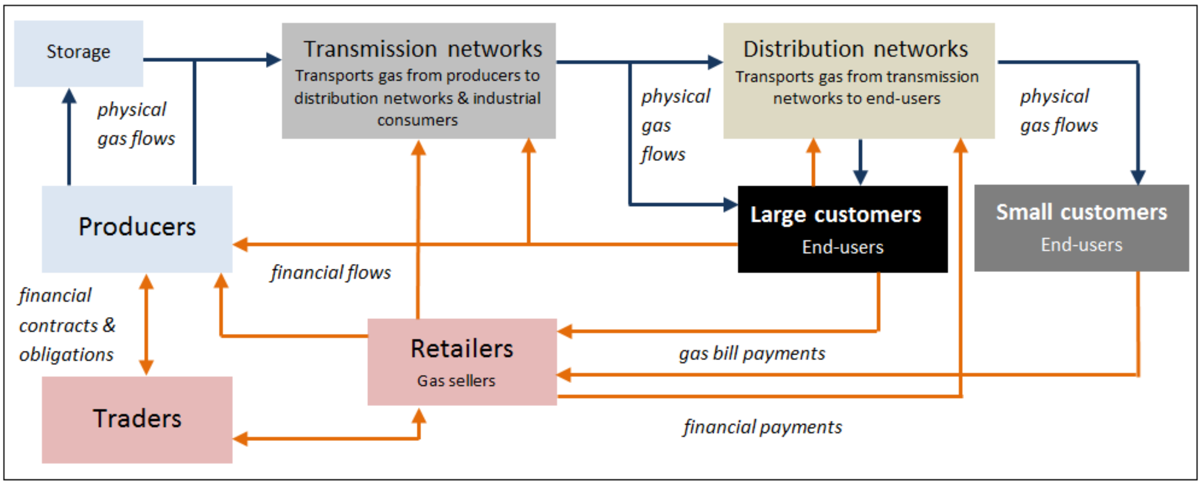
Committed Project	Ownership	Share	Operator	Nameplate Capacity	Train/ Capacity	Actual / expected operating date	Location: Basin LNG Plant
Ichthys LNG/ Condensate	INPEX	66%	INPEX	8.4 Mtpa	Train 1 – 4.2 Mtpa	H1 2017	Browse Darwin
	Total	30%			Train 2 – 4.2 Mtpa	H2 2017	
	Tokyo Gas	1.6%					
	Osaka Gas	1.2%					
	Chubu Electric	0.7%					
	Toho Gas	0.4%					

Source: BREE and company reports.

Prices

As illustrated in figure 1.18, there are separate financial and physical flows within the gas market.

Figure 1.18 Financial and physical flows of gas



Although there are spot gas markets in the eastern market, Australian domestic gas trade is dominated by bilateral long-term contracts between sellers and buyers. These contracts generate certainty for large producers and consumers to underwrite significant upstream and downstream gas investments. Gas contracts tend to vary on a case by case basis, but usually are priced at an average rate in dollars a gigajoule and a charge based on peak demand. These charges are multiplied by an escalator, such as the consumer price index, over the life of the contract. Factors that tend to influence contract negotiations include (IMO 2014):

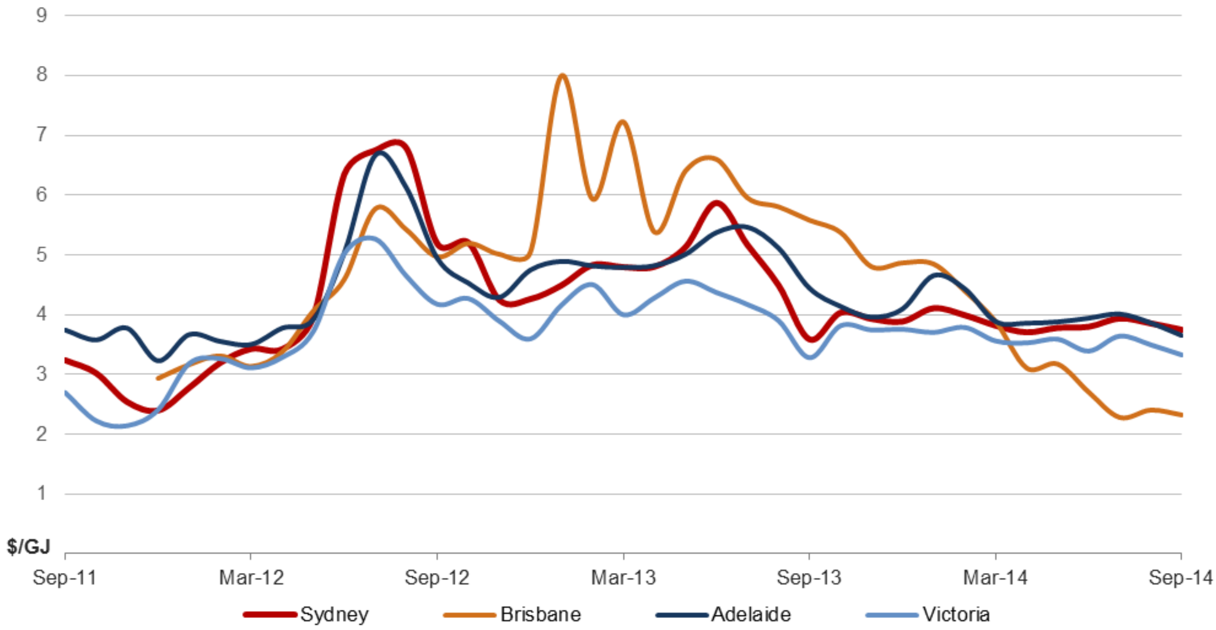
- the volume of gas
- the length of the contract
- the reliability and availability of the supply
- the use of the gas
- the status of the customer
- the relationship between the customer and supplier

The start of LNG production in the eastern market will result in all three of Australia's natural gas markets exporting LNG. As the eastern gas market transitions to linking to the LNG export market it is experiencing substantial increases in long term gas contract prices, which is affecting all domestic demand sectors due to the relatively large size of this new source of demand and the higher prices gas exporters are prepared to pay (Department of Industry and BREE 2014). The higher value available from selling gas for exporting as LNG is not alone in putting upward pressure on domestic gas prices. The large size of export demand for gas is also increasing the cost of supply due to the need to develop and produce from higher cost resources either in more remote locations and/or in the form of unconventional gas.

Spot trading markets exist only in the eastern market. Victoria has the Declared Wholesale Gas Market, which is operated by the Australian Energy Market Operator (AEMO) to provide day-ahead balancing and managing of gas flows in the Victorian Transmission System. AEMO also operates short-term trading markets (STTMs) to provide balancing and market trading at hubs in Brisbane, Sydney and Adelaide. In 2014, a gas supply hub at Wallumbilla in Queensland began operating based on a brokerage model with voluntary trading between gas producers and shippers.

Prices in the short-term and wholesale trading markets in the eastern market have steadily decreased from the relatively high levels experienced in 2012-13. Prices in the Brisbane STTM in particular have declined to low levels due to the production of ramp gas for the LNG projects entering a market with very flat demand (figure 1.19).

Figure 1.19 Indicative eastern market gas prices



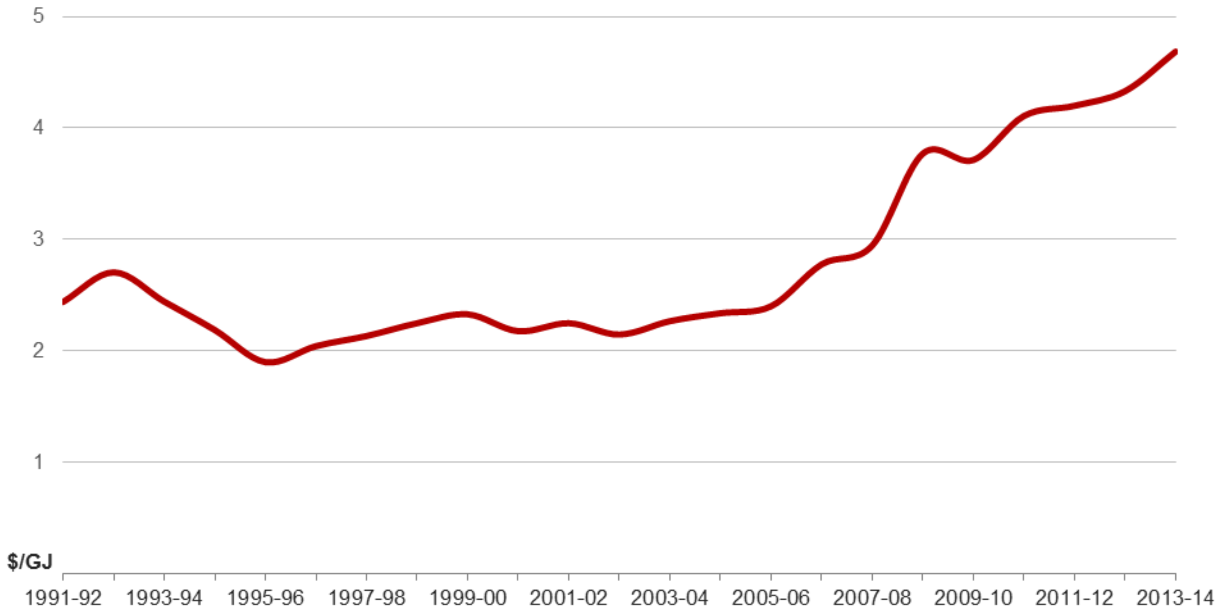
Note: STTM prices are ex-ante; they include both the cost of the gas and the cost of transporting it to each hub. The Victorian Wholesale price is ex-post; it includes only the cost of the gas.
Source: AEMO (2014).

The majority of gas in the western domestic market, like the east, is sold under long-term bilateral contracts. These contracts, many of which have historically been with the North West Shelf Project, have created a stable and affordable gas supply that has resulted in Western Australia becoming the largest gas consuming state in Australia.

The average price of gas traded under these contracts is reported by the Western Australian Department of Mines and Petroleum on an annual basis (figure 1.20). Western Australia does not have a short term or market clearing price. As such the annual price reflects the total volume of gas sold divided by its value. The Western Australian Independent Market Operator estimates that 98 per cent of gas traded in the state is done so under long term bilateral contracts (IMO 2014).

Prices have, in real terms, been relatively flat over the past two decades, being contained between $3 and $5 a gigajoule in 2013-14 dollars. The Varanus Island gas plant explosion in 2008 resulted in a spike in prices that has since moderated as new production from the Reindeer and Macedon fields has come online.

Figure 1.20 Realised western market gas prices



Source: WA Department of Mines and Petroluem (2014).

A number of long term legacy contracts at relatively low prices, which comprise the majority of gas traded in Western Australia, have come to an end over the last year. These contracts are, and will continue to be, renegotiated in a significantly more competitive environment in which the state is undergoing a dramatic expansion in liquefaction capacity. As such, the Independent Market Operator's latest *Gas Statement of Opportunities* forecasts a consistent rise in gas prices to $7-$8 a gigajoule in 2013-14 dollars by 2020.

Conclusion

Australia has abundant gas resources that support a large and dynamic industry supplying domestic and export markets. This industry is undergoing a rapid, perhaps unprecedented, period of growth and change, which will result in Australia becoming a world leading LNG exporter by the end of the decade.

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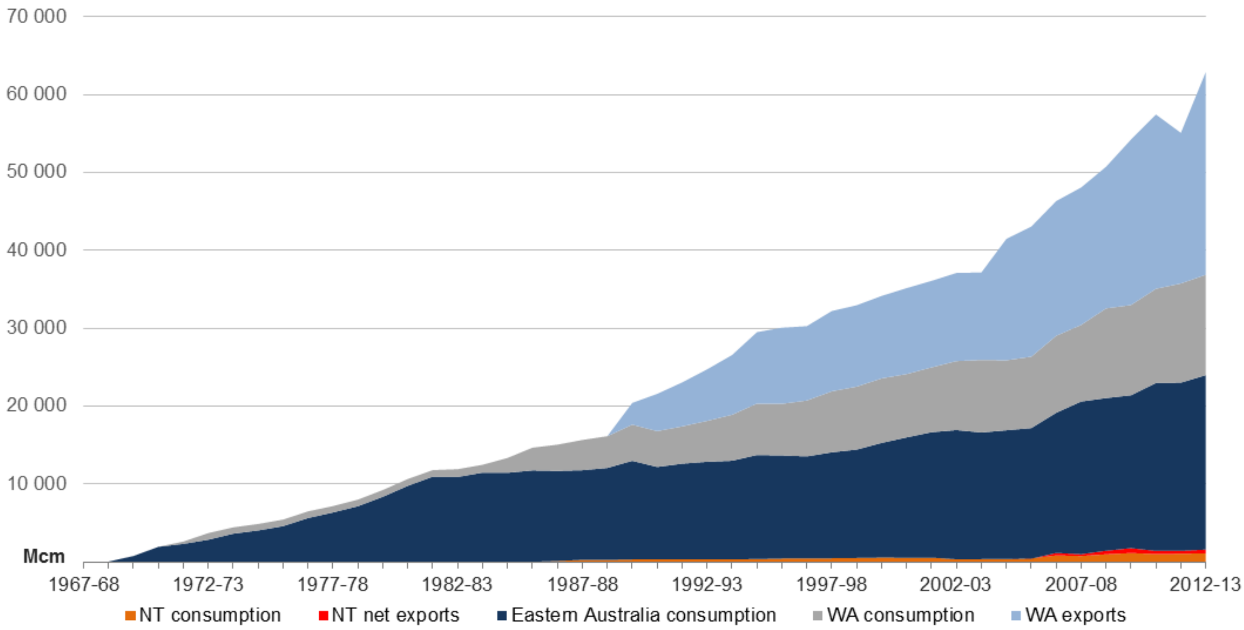
2 THE DEVELOPMENT OF AUSTRALIA'S NATURAL GAS INDUSTRY

Introduction

Natural gas production on the Australian east coast commenced with the exploitation of low cost conventional gas fields. This enabled a stable and long-term market to develop for gas supplies to meet domestic demand. In the western market, the focus was more on developing the large offshore conventional gas reserves principally to serve export markets through the supply of LNG. The LNG export sector was crucial to the development of the industry in Western Australia. Figure 2.1 illustrates the growth in natural gas production and its use in satisfying domestic and LNG export demand over the 45 years ending in 2012-13.

Figure 2.1 Natural gas production by end-use market



Source: BREE (2014), Australian Energy Statistics.

Large gas reserves, particularly those in the north west of Western Australia, and the small scale of the domestic market, were the key drivers in the development of LNG exports. Japan was the foundation customer for Australian LNG exports.

Australia has exported gas since 1989 from the North West Shelf Venture in Western Australia. Production has steadily expanded to the extent that now exports account for almost half of Australia's total gas production.

While most of Australia's history of gas exploration has focused on conventional gas resources, more recently in the eastern gas market this has shifted to unconventional gas in the form of CSG. The scale and speed of the development of CSG from the Surat and Bowen coal basins in Queensland in response to the commercial opportunities provided by LNG exports has been dramatic and unprecedented.

This chapter provides an overview of the history of the Australian onshore and offshore gas industry and highlights the key factors contributing to its development. It then focuses on the development of the LNG sector and the role of government in particular. Gas market reform is briefly discussed before concluding.

Development of the onshore natural gas industry

Gas development in Australia is intertwined with shifting state and Commonwealth energy policies. It is a fluctuating history of subsidies and grants coupled with taxation and royalty relief to encourage the development of the industry. This history was interspersed with periods of restrictions on exports, foreign ownership limits, price controls and direct government ownership.

Petroleum exploration in Australia was initially driven by the hope and expectation of oil discoveries. Booming demand for transport fuels to satisfy a rapidly growing population was tempered by conflicts and price shocks that emphasised Australia's vulnerability to supply disruption. An indigenous oil supply was widely seen as vital for the security and the development of the nation.

In 1900, natural gas was first discovered in Australia at Roma in southern Queensland. However, it was not until the early 1960s and the discovery of major commercial volumes of gas in south east and central Queensland that gas became widely seen as a commercial commodity. Significant discoveries in the Cooper Basin in northern South Australia, and offshore Victoria and Western Australia later in the decade, cemented the rise of natural gas from a nuisance by-product associated with the search for oil to an important component of the Australian energy mix.

Onshore gas development was driven by the opportunity to supply the larger coastal cities and industry with affordable energy. The construction of gas transmission and distribution pipelines was an essential factor in commercialising the newly discovered natural gas resources. Pipeline systems began supplying onshore natural gas to residential and commercial customers in Brisbane (Roma to Brisbane pipeline) and Adelaide (Moomba to Adelaide pipeline) and Melbourne (Longford pipeline) in 1969, Perth (Parmelia pipeline) in 1971, and to Sydney (Moomba to Sydney pipeline) in 1976. Many of these systems were either owned or underwritten by state or Commonwealth governments.

In the Northern Territory, natural gas from the Amadeus Basin was supplied to Darwin in 1986. The 1500 kilometre pipeline was largely underwritten by a contract to supply Darwin and its power station with gas, together with smaller amounts to larger regional communities along the route. There was also an expectation, never realised, that eventually the Gove Alumina Refinery would be supplied with gas.

It is instructive to note that by the mid-1990s all the capital cities in the eastern states and South Australia still only had one source of gas supply. This situation exposed these major demand centres to supply risk, as experienced in Victoria following the gas explosion at the Longford gas processing plant in 1998, and resulted from government imposed constraints on the use and interstate trade of gas.

By 2003, an integrated transmission pipeline network had been created that provided four capital cities in these states with multiple sources of gas supply. This development was facilitated by major reforms to the gas industry in the mid-1990s. In response to the broader economic reforms advocated by the 1993 Hilmer report on national competition policy, the Council of Australian Governments (COAG) implemented initiatives, such as removing legal restrictions on interstate trade and mandating third party access to pipeline infrastructure. Along with a major regulatory outcome in the establishment of the Gas Access Regime for the regulation of pipelines in 1997, COAG initiatives resulted in greater basin to basin competition and security of gas supply by the early 2000s.

In the early 2000s, Cooper Basin conventional gas production peaked and then started to decline, with the smaller Queensland fields also declining. Coupled with rising domestic demand, offshore production from Victoria became increasingly important for the east coast domestic market. During the first decade of the new millennium, onshore fields in the Northern Territory also started depleting and from 2009 the offshore Blacktip project replaced the Amadeus Basin as the Territory's major gas supply.

By the mid-2000s CSG in Queensland was also becoming more important. CSG was first produced as a by-product of coal mining in New South Wales in the early 1990s, but it was not until 1996 that the first exploration and commercial production of CSG began in Queensland.

The development of CSG in Queensland was assisted early on by the introduction in 2005 of the state government's policy of mandating a fixed percentage of electricity to be generated by gas (the Queensland Gas Scheme). This policy was originally introduced to reduce greenhouse gas emissions and to stimulate gas production to replace declining conventional gas reserves. CSG from the Surat Basin went into south east Queensland through the existing gas network. From 2004, gas from the northern Bowen Basin was piped north to Townsville for electricity generation and industry around the city.

More recently, as techniques to produce CSG were refined, the realisation of the potential resources available from Queensland coal seams also drove the development of the east coast LNG industry. This led to a flurry of mergers and acquisitions as companies sought to put together sufficient acreage and financing to underwrite a project (with large Australian and multi-national oil and gas companies becoming the dominant players in the sector). The first investment decision to proceed with an LNG project on the east coast occurred in 2010. The three projects in construction will progressively come into production from the end of 2014 and reach full production towards the end of the decade.

Development of the offshore natural gas industry

The offshore gas industry commenced in Australia with the first well being drilled in the Gippsland Basin in 1965. Oil was discovered in 1967, and natural gas reached Melbourne in 1969. Offshore Otway gas production commenced in 2005 with the Minerva field, followed by production from Casino and Geographe/Thylacine in 2006 and gas from the Bass Gas Project.

In north-western Australia, like many other areas, exploration was originally driven by the search for oil and the discovery of large gas resources in the early 1970s proved difficult. Unlike Victoria, gas fields in the western market were further from shore and much further from demand centres, which together reduced the commercial attractiveness of supplying the small domestic market. However, the emergence of the LNG export industry provided the impetus and economies of scale necessary to underpin the large development costs and progress gas production.

First domestic gas was delivered in 1984. Similar to onshore gas development in eastern Australia, initial production and development costs were underwritten with guaranteed take or pay contracts with the State Energy Commission of Western Australia and the Western Australian state government backed the construction of the Dampier to Bunbury Pipeline.

Further north, a number of oil and gas discoveries had been made offshore. Some oil projects progressed to development based on floating production, storage and offtake (FPSO) technology which enabled production on the site of the oil field using either converted oil tankers or purpose built facilities.

The discovery in 1996 of the large Bayu-Undan gas field in the Joint Petroleum Development Area (JPDA) with East Timor kicked off development in the Timor Sea. The field was relatively high in condensate, propanes and butanes (LPG) which provided an early income stream for developers ahead of the gas phase of the project. The gas phase came on stream in 2006 when the single train Darwin LNG Project commenced exports. No domestic gas was supplied from the LNG project for Darwin although later connections enabled emergency gas to be supplied to the city.

In 2009, the offshore Blacktip gas field was developed to replace onshore gas supplied from the Amadeus Basin where existing known fields had largely depleted. Similar to other gas developments, Blacktip was underpinned by a take or pay contract with the government-owned Northern Territory Power and Water Corporation.

LNG exports – the opportunity to enhance value

The development of Australia's gas industry has been driven by opportunities to commercialise and enhance the value of Australia's large endowment of natural gas resources. The most significant of these opportunities is linking to higher value export gas markets through the production and sale of LNG.

The proximity of Australia to major LNG demand centres in the Asian market, and to a lesser extent in other regional LNG markets, attracted large investments from international petroleum exploration and development companies and large LNG customers. Historically, the major gas fields for LNG production are in the conventional gas basins of Carnarvon and Bonaparte situated off the Western Australian and the Northern Territory coasts, respectively.

The North West Shelf Venture was a commercial response to the changing dynamics in the Atlantic and Asia Pacific LNG markets, which began in the early to mid-1970s. From the early to mid-1970s to 1996, the growth of LNG demand in the Atlantic market slowed significantly. North American LNG demand fell due to major events in global energy markets (Jensen 2004, Kilian 2010):

- the two oil price shocks (in 1973–74 and 1979–80)
- the widespread nationalisation of the international oil companies' concession areas within OPEC
- the restructuring of the North American gas industry

Prior to 1996, LNG demand in the Asian region grew as Japan was joined by South Korea and Chinese Taipai as importers. Growth in demand for LNG in the Asian market was also strong and was met by four main suppliers in the region – Indonesia, Malaysia, Australia and Brunei (Jensen 2004).

There have been close commercial relationships between Australia's LNG projects and customers. The North West Shelf venture's initial decision to invest was underpinned by long-term LNG sale agreements with eight foundation customers in Japan. The facility, which is operated by Woodside, was progressively expanded to five trains in three stages in 1992, 2004 and 2008 to its current nameplate capacity of 16.3 Mtpa as a result of commercial arrangements with customers in Japan, South Korea and China.

Several key factors contributed to the ongoing growth in the LNG markets from the late 1990s into the 2000s (Jensen 2004):

- Combined cycle power generation for growing electric power markets
- Effects of technology on cost reduction making previously uneconomic trades attractive
- Environmental concerns
- The embrace of gas by previously 'gas poor' economies
- The growing concern for traditional supplies in the face of growth
- The 'stranded gas' phenomenon

These factors drove higher demand for LNG, thereby enhancing its economic returns and the prospects for further investment in LNG projects. The favourable outlook for LNG in Asia in the early 2000s resulted in Australia's second LNG liquefaction project – the 3.7 Mtpa Darwin LNG facility operated by ConocoPhillips in the Northern Territory – being commissioned in 2006. It is supplied with gas from the Bayu-Undan fields located in the Timor Sea. The third of Australia's operating LNG facilities, Woodside Energy's 4.3 Mtpa Pluto LNG, was commissioned during 2012-13. It is located on the Burrup Peninsula north-west of Karratha in Western Australia and is supplied by gas from fields in the Carnarvon Basin. Investment in both the Pluto LNG and Darwin LNG projects was underpinned by long-term sales agreements with customers in Japan.

The LNG industry's success – a partnership with governments

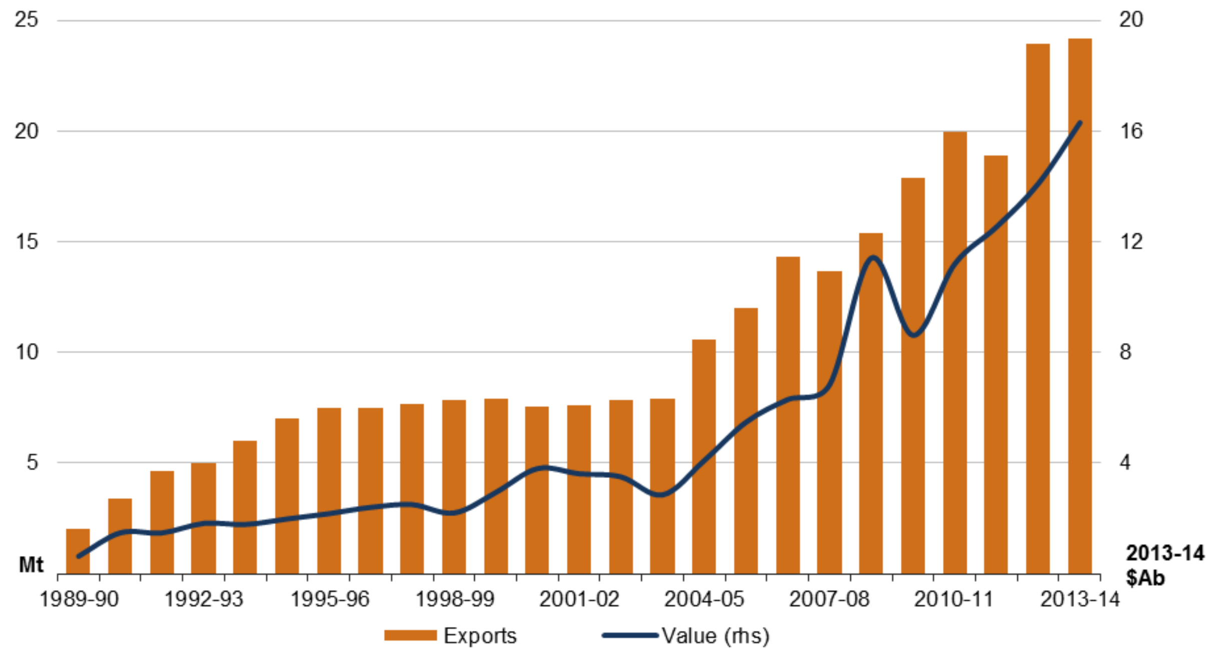
Both government and industry have been instrumental in transitioning the gas industry towards more reliable, secure and competitive domestic gas markets. Governments have also played an integral role in creating a successful LNG industry in Australia.

The global LNG market is 50 years old this year and Australia is now in its 25th year of exporting LNG.[1] Over that time the Australian LNG industry has gone through successive phases of expansion to meet rising demand, predominately from the Asian region. Figure 2.2 illustrates the growth in LNG exports and value from 1989-90 to 2013-14. For the first 20 years, from 1989 to 2008, LNG export volumes grew at a compound annual growth rate of 11 per cent. In the following five years up to the

[1] In 1964, Algeria was the first country to have a commercial-scale liquefaction plant.

current year the annual growth rate was 9 per cent. For the next five years ending in 2018–19, the annual growth rate is projected to be just over 23 per cent.

Figure 2.2 LNG exports and value



Source: BREE.

It is estimated that the Australian LNG industry contributed A$68 billion in taxes and royalties over the period 1989 to 2012 (MacDonald-Smith and Parkinson 2014), and it is projected that by 2020 these payments could reach A$13 billion a year (Hewett 2014).

Over the last 25 years, the Australian LNG industry has learned that a key factor in its success is cooperation with all levels of government to improve the investment environment for LNG projects (Pritchard 2007). Governments contributed by improving the investment environment through industry policies, and appropriate regulatory and fiscal regimes.

Policy support

During the development of the LNG industry in Australia, governments adopted several major policy initiatives directly and indirectly aimed at supporting the industry:

- The 2000 LNG Action Agenda, which provided strong policy support for the development of Australia's LNG export industry
- The 2001 Australian Industry Participation National Framework Agreement, which provided a uniform national approach to major investment projects
- A strategic alliance in 2006 between the upstream oil and gas industry and the Australian Government, State Governments and the Northern Territory Government that aimed to ensure by 2015 that Australian LNG production exceeded 50 Mtpa

- Support from the Commonwealth government for the Australian Petroleum Production and Exploration Association's (APPEA) Strategic Leaders Report of 2007 that canvassed options for unlocking the potential of the oil and gas industry

The LNG Action Agenda is considered a particularly significant government initiative for the sector (Thompson and MacClean 2006). This agreement between the Australian Government and the LNG industry committed the Government to actions that would enhance the competitiveness of the industry and remove or mitigate impediments to its growth. The Agenda resulted in specific outcomes relating to greenhouse gas emissions, taxation, customs and tariffs, Australian industry participation, streamlining the approval processes for projects and effective industry/government LNG marketing and promotion (IEA 2005).

These major policy initiatives either built on or enhanced broader measures implemented by the Australian and state and territory governments to facilitate the investment in, and development of, major projects. The measures included the Australian Government's establishment of the Major Project Facilitation program, and more recently, reforms by the states and territories to improve their major project approvals processes.

In addition to broad-based policy initiatives for improving the investment environment for LNG projects, the Australian, state and territory governments also have regulatory responsibilities and other forms of direct involvement that affect investment in LNG projects. The three most important contributions made by government in relation to investment in LNG projects in Australia are (Thompson and MacClean 2006):

- Providing the approval process for projects with foreign ownership (through the Foreign Investment Review Board)
- State governments facilitating projects (for example, state ratified agreements for project development)
- Creating favourable regulatory and fiscal conditions

The Australian and state and territory governments also play a crucial role in facilitating investment in the development of petroleum resources through the information they provide. Australia has a history of government providing pre-competitive geoscience information to attract investment in resource exploration and the responsible development of Australia's resources. The Australian Government and state and Northern Territory governments have a shared responsibility for collecting geoscience information through their respective geoscience organisations. The states and Northern Territory organisations each collect onshore pre-competitive geoscience information. The Australian Government agency, Geoscience Australia, is primarily responsible for offshore mapping and pre-competitive information, but also operates formally with the state and territory agencies under the National Geoscience Agreement to gather and assess onshore geoscience information.

Regulatory and fiscal regimes

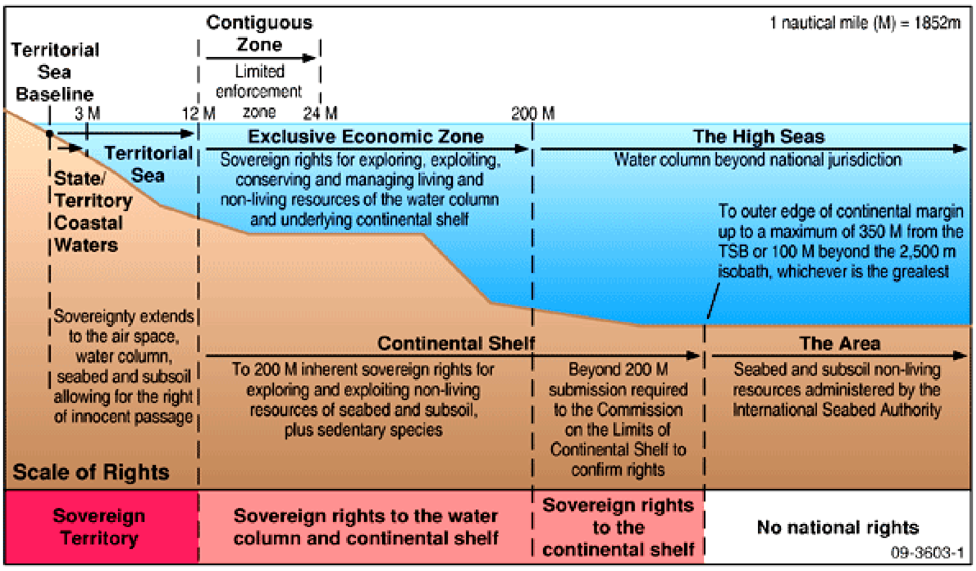
The regulatory regimes applying to resource development activities have been important to improving the investment environment for Australian LNG projects, and include the following elements:

- schemes for the licensing of applicants to explore for, and to produce, the state's resources
- environmental, planning and occupational health and safety regulation
- taxation of the resource development

Australia's mineral and petroleum resources are owned by the State which, on behalf of the community, exploits and administers the property rights it grants to the private sector to undertake exploration, development and production activities. Australia's federal system of government divides powers between the Australian and the state and territory governments.

The *Seas and Submerged Lands Act 1973* establishes a range of maritime zones. As illustrated in figure 2.3, in Australia's territorial sea, the states and the Northern Territory are accorded legislative powers over the first three of the 12 nautical miles extending seaward from the baseline.

Figure 2.3 Australian maritime jurisdictions and boundaries



Source: Symonds et al. (2009).

State and territory governments are responsible for decisions concerning the release, award, and management of oil and gas acreage and tenements located onshore and in coastal waters up to three nautical miles offshore. Consequently, there is a range of regulatory systems and regulations between jurisdictions (Productivity Commission 2013).

The Commonwealth offshore area is located beyond the coastal waters, extending through the remaining nine nautical miles of the territorial sea and out to areas of Australia's declared continental shelf beyond the Exclusive Economic Zone (as defined in the *Seas and Submerged Lands Act 1973*). The Australian Government in consultation with the relevant states and the Northern Territory is the jurisdiction responsible for the release, award and management of oil and gas acreage and tenements in the Commonwealth offshore area.

The legislative framework for offshore petroleum activities including licensing, regulation and safety is provided by the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act). Its objective is to establish a regulatory framework that is effective in promoting the commercialisation of Australia's petroleum resources, and sets out the legislative requirements for administering exploration permits, retention leases and production licences. Regulatory powers for individual states and the Northern Territory are derived from each jurisdiction's legislation relating to onshore or offshore petroleum activities.

However, with the exception of end-of-operation environmental restoration, the OPGGS Act does not cover the regulation of activities with respect to their impact on the environment or native title. Of the wide range of additional and separate Commonwealth legislation covering the environment and native title impacts, the *Environment Protection and Biodiversity Conservation Act 1999* is considered the most relevant to offshore petroleum activities (Hunter 2010). The overarching requirement of this Act is that a titleholder must avoid any action not approved by either the Minister or an approved delegate that will, or is likely to, have a significant impact on the environment.[2]

Responsibilities for health and safety, well integrity and environmental management of offshore oil and gas operations have been amalgamated into a single national regulator – the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) – to reduce regulatory burden, standardise offshore petroleum regulation, and produce a best practice regulatory model.

As is the case with regulatory systems, fiscal regimes also vary between jurisdictions. All three main types of tax used to compensate the community for the exploitation of its petroleum resources are applied in Australia: rent-based tax, income-based tax and output-based royalty. The Petroleum Resource Rent Tax (PRRT) is the principal tax levied by the Australian Government on offshore and onshore petroleum projects (excluding the JPDA in the Timor Sea) that generate profits from the sale of marketable petroleum commodities (MPCs). The PRRT aims to provide 'a fiscal regime that encourages the exploration and production of petroleum while ensuring an adequate return to the community'.[3] As a rent-based tax, the PRRT collects only a percentage of a petroleum project's economic rent. The PRRT is applied at a rate of 40 per cent of a project's above-normal profits and therefore is designed to not affect investment.

Petroleum companies are also subject to income tax on their earnings before interest and tax at a company tax rate of 30 per cent. Where applicable, states and territories collect a percentage of either the gross or net value of petroleum products at the wellhead (an *ad valorem* royalty) at a rate legislated by each jurisdiction. Although there are exceptions, royalty rates mostly vary between 10 and 12.5 per cent.

Changing needs - gas market reform

Following COAG's response to the Hilmer report, gas industry reform continued with the release in 2002 of the COAG instigated Parer Review of the strategic direction for stationary energy market reform. As a result, significant structural changes affecting the governance and operation of the gas industry in the eastern gas market were made through the creation and empowerment of institutions in the form of the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO).

[2] *Environmental Protection Biodiversity Conservation Act 1999* (Cth) part 9.

[3] Mayo, Wayne cited in Parliament of Western Australia (2014a): p.35.

Along with COAG, the gas industry, particularly through the Gas Market Leaders Group, has been instrumental in adopting measures to improve outcomes in domestic gas markets. The Gas Market Bulletin Board, Short Term Trading Markets, Gas Statement of Opportunities and AEMO originated from the National Gas Market Development Plan presented by the Gas Market Leaders Group to the Ministerial Council on Energy in 2006. More recently, reforms to improve the gas market are being developed through the Australian Gas Market Development Plan and its underlying principles, which were adopted by the Standing Council on Energy and Resources in 2012.

The need for gas market reform continues as Australia's domestic gas markets are increasingly integrated with global gas markets through the export of LNG. The linking of domestic and international markets has and continues to present both opportunities and challenges for the development of the domestic and LNG market. The Department of Industry and BREE's recent *Eastern Australian Domestic Gas Market Study* informed the Government on market conditions and suggested fourteen potential new gas market reform principles that could guide reform onwards (Department of Industry and BREE 2014).

Conclusion

The development of Australia's gas industry has been characterised by the growing importance of natural gas resources for domestic use and as an export commodity. In the very early years, natural gas in Australia was considered of little value with no clear commercialisation pathway and with a focus on the discovery of oil resources. As the size of the natural gas resource was realised, the quest began to find uses for gas that would allow significant discoveries to be commercialised. This drove the ongoing development of the onshore and offshore natural gas industry.

The demand for natural gas was initially limited to a few industrial users and as a replacement for manufactured town gas. As the number of gas discoveries increased and pipeline infrastructure expanded, this increasingly enabled large industrials to access gas. In turn the demand for gas in electricity generation and for residential and commercial customers also grew.

During this period, supply and demand conditions coupled with government interventions on wholesale prices resulted in the price of gas in Australia's domestic markets being significantly lower than in many other gas markets in other countries.

The advent of value-adding LNG export opportunities progressively changed this situation in the western market. We are currently seeing the eastern gas market linking to international markets. The development of CSG reserves on the east coast coupled with the growing demand in Asia, has stimulated large scale investment in new LNG projects. This linking to international markets has also impacted domestically as prices for gas have adjusted towards international benchmarks.

Since the LNG industry's beginnings, governments have played a key role in its development and expansion by improving the investment and operating environment through industry policies, and regulatory and fiscal regimes. Over the last two decades, governments have also shown they are integral to assisting the domestic gas market to develop and adapt to changes thorough their commitment to an ongoing process of reform.

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3 COST COMPETITIVENESS: A KEY CHALLENGE TO AUSTRALIA'S LNG SECTOR

Growing gas supply competition in the Asian region

Recent long-term projections by energy analysts show that natural gas is continuing to grow in importance in the global energy mix, and the Asian region is becoming the major centre for international trade in gas (BP 2014, IEA 2013). The scenarios portrayed in these projections suggest the ongoing demand in the region will be driven by a range of factors relating to total energy demand and energy intensity as countries undergo various stages of economic development (industrialisation and urbanisation), and address issues concerning energy security and environmental objectives.

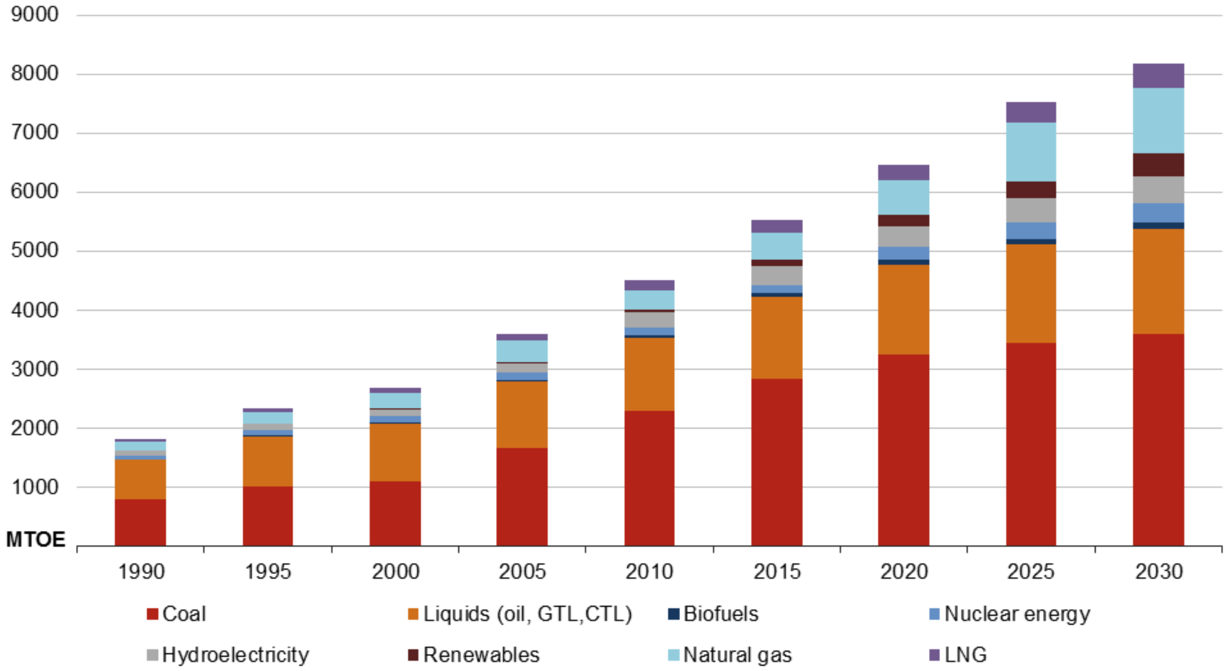
While indigenous gas and imported pipeline gas are significant options available to many LNG consuming countries to meet their natural gas demand, LNG imports are expected to remain an important and growing source of gas supply. Growth in LNG demand in the Asian region will mainly depend on Japan, China and India and the specific policies adopted by each country regarding gas consumption and options for gas production.

Over the medium term, competition for LNG supply to the Asian region is looking strong. The main potential competitors over the next decade are Australia, the United States (US), Canada, East Africa, Papua New Guinea (PNG) and Russia. The growing supply-side competition is putting upward pressure on development costs for LNG projects and downward pressure on LNG export prices. As a result, regional gas markets are becoming more flexible and interconnected, which is leading to the narrowing of differences between regional gas prices, an increase in spot and short-term trading of LNG, and the move away from oil indexed pricing in the Asian region.

Given this context, LNG demand projections over the medium to longer terms need to be considered in light of not only developments in LNG markets, but also expectations regarding other factors. These include the relative costs of alternative sources of energy, opportunities to develop indigenous gas resources and import pipeline gas, government policies and regulations, and geopolitical drivers. This is important, as due to its relatively higher price, LNG demand is far more susceptible to changes in both the demand for competing energy sources and overall energy demand than that for pipeline and indigenously produced gas.

For many countries LNG is regarded as a balancing energy source to satisfy demand. The balancing role of LNG has implications for projecting its demand, particularly in the longer-term. Figure 3.1 highlights this balancing role and emphasises the susceptibility of LNG demand to changes in total energy demand and the demand for competing energies. It is based on information of historical and projected energy demand in the Asian region, and the supply of different types of energy used to satisfy that demand.

Figure 3.1 Energy demand in Asia, 1990–2030



Note: 'Natural gas' includes indigenous production and pipeline imports.
Sources: BP(2013 and 2014); Jensen (2004); ABARE (2004) and BREE (2014).

Figure 3.1 shows that although growing in absolute terms, LNG makes only a relatively small contribution to satisfying total energy demand in the Asian region. Given the relatively high price of LNG in the Asian market, any changes to overall energy demand or changes to the availability and/or the relative prices of competing energy sources is likely to significantly affect LNG demand. Projecting how LNG demand and supply conditions in the Asian region will play out over the medium term is, therefore, prone to very dynamic and uncertain factors. Such as the Fukushima disaster in Japan and the Russia and China agreement on pipeline gas from Russia's Siberian gas fields.

Australia is on track to become the world's largest exporter of LNG before the end of this decade. This will occur in a period of increasing competition from new entrants supplying LNG to the Asian market. Notwithstanding the inherent uncertainties on forecasting LNG demand, it is important to gain an understanding of the relative cost competitiveness of Australia as an LNG supplier compared to other countries that are or could become rivals.

Cost competitiveness of Australia's LNG sector in the LNG value chain

A country's cost competitiveness as an LNG exporter relates to the relative ability and performance of its LNG sector to export to international customers in a particular market, compared to the LNG sectors in other countries exporting to the same market. The fundamental economic justification for an LNG project is its competitiveness in terms of the cost of producing LNG and, therefore, the related price required from customers to make the project commercially viable.

The LNG value chain

The oil and gas sector may be divided into three major components: upstream, midstream and downstream. The upstream sector is associated with the exploration and production of natural gas from offshore or onshore fields. The midstream sector mainly involves liquefaction, pipeline transport and shipping. The downstream sector commonly refers to LNG receiving or regasification, and the marketing and distribution of the products to consumers. Optimal operation of a large LNG project requires taking into account many of these components, including the upstream production system, midstream shipping and downstream to the buyer and eventual consumer.

The LNG value chain consists of five interdependent activities (figure 3.2):

- Exploration and production of natural gas
- Liquefaction of natural gas into LNG
- Transport from liquefaction facility to the final destination
- Receiving (regasification) and storage at the final destination
- Access to end users

Figure 3.2 The LNG value chain

LNG is produced from either conventional gas or unconventional gas (such as shale and CSG). Following exploration and production from onshore or offshore fields, natural gas is transported by pipelines to the liquefaction facilities where it is converted to LNG. LNG requires natural gas that is filtered and purified, so as not to damage equipment during the conversion from gas to liquid, and in order to meet the specifications of the customer. As a result, the liquefaction process produces a natural gas consisting of close to 100 per cent methane. The liquefaction process reduces the volume of gas by a factor of around 600, in other words 1 cubic metre of LNG at -163°C has the same energy content as 600 cubic metres of natural gas at ambient temperature. The density of LNG is around 45 per cent that of water.

The LNG is stored in insulated tanks and then loaded into specially constructed vessels, which are designed to keep the gas in a liquid state as it is shipped to its destination country. Shipping is the means of connecting LNG suppliers with buyers. On arrival at its destination, the LNG is converted to its original state through a heating process in a regasification facility. At the regasification facility, storage tanks enable a continuous flow of gas into the pipeline transmission network. Furthermore, these storage tanks can be used to provide gas for periods of peak demand. The natural gas is fed from storage tanks into the national pipeline transmission and distribution network through which it is physically delivered to end users. In some instances, LNG is transported in its liquid state by truck to single consumers (e.g. from the US to Mexico).

Approach

The examination of cost competitiveness in this study focuses on the main supply components of the LNG value chain consisting of gas production in the upstream sector, and liquefaction and shipping in the midstream sector. Although regasification is an essential part of the LNG value chain, it is not included in this analysis because it is a relatively low cost component.[1]

To examine the relative cost competitiveness of Australia's LNG sector in the Asian LNG market's value chain, data from the Nexant World Gas Model (WGM) (Appendix B) is used to assess the long run marginal cost (LRMC) of the key components: gas production, liquefaction and shipping.[2] The WGM has extensive data on gas production and trade that includes:

- historical and forecast energy prices
- historical and forecast production
- pipeline capacities and tariffs
- liquefaction and regasification terminals and costs for operating, under construction and proposed projects
- LNG and pipeline gas contracts
- storage capacity and tariffs
- LNG shipping costs, including and route data
- historical and forecast gas demand

This data along with the assumptions adopted in the WGM provide a consistent basis for assessing relative differences in the LRMC of LNG projects in different countries. LRMC is essentially forward looking as it reflects the expected value of costs that are likely to arise from changes in conditions, including demand, over the longer term. Unlike the short run, in which some costs are fixed, there are no fixed costs in the long run. This means that the LRMC is an estimate of changes in the cost of all inputs and, therefore, captures the cost of an additional unit of capacity.

For the purpose of this analysis LRMC is measured in USD per million British thermal units (mmbtu).[3] The LRMC reflects the cost at which an additional unit of gas production, liquefaction and shipping capacity are supplied, provided that investment takes place over the projection period.

The cost of an increment of capacity is calculated in present value terms, that is, by considering the equivalent value today of a series of net cash flows from the investment that will occur in the future. A discount rate is applied to estimate the LRMC that reflects the time value of money of the investment and the risks inherent in the project. The discount rate also represents a measure of the

[1] The cost of regasification is a factor in the overall import cost of natural gas, but it is borne by the importer and charged back to industrial and power users in the importing nation. Although the cost affects the users, it does not reflect on the competitive position or value of the LNG cargo (Moore 2014).

[2] In the WGM, LNG liquefaction or shipping LRMC is estimated for uncontracted flow only, as the contract price is assumed to be the delivered price. However, LRMC reflects the economic principle that the contracted price also reflects the underlying costs of LNG liquefaction or shipping.

[3] To convert million British thermal units to gigajoules multiply by 1.055.

rate of return expected by the parties funding the asset. A post-tax discount rate of 10 per cent is representative of a rate typically used by oil and gas investors.

The analysis does not account for a 'depletion cost', which is usually included in exhaustible resource models.[4] Empirical evidence has shown that new discoveries and technological progress have significantly mitigated the effects of finite availability of many non-renewable resources on their scarcity for production and consumption activities.

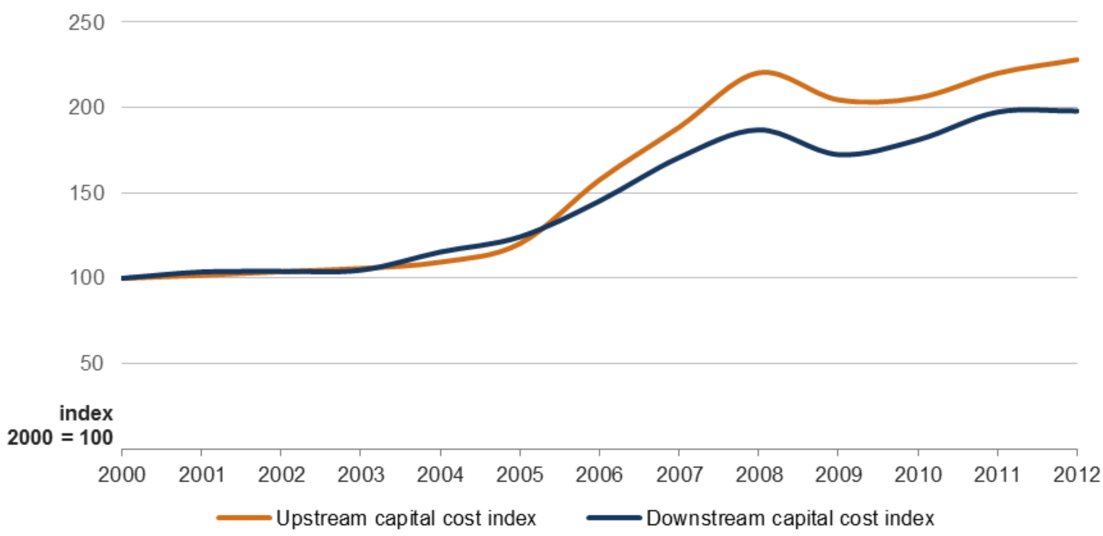
In light of the long projection period and the inherent uncertainties in future supply and demand conditions, results from this analysis should be treated as relating to only one of many possible scenarios reflecting the base-case data and assumptions of the WGM. The purpose of this analysis is to contribute to understanding the cost competitiveness of LNG supply by providing qualitative insights rather than quantitative results.

The structure of costs along the value chain

The capital costs in the LNG value chain vary significantly. A typical breakdown of the cost structure of the value chain shows that exploration and production account for 15 to 20 per cent of the total cost of supplying LNG, liquefaction accounts for 30 to 45 per cent, shipping 10 to 30 per cent, and regasification and distribution combined account for 15 to 25 per cent (EIA 2003).

Over the past decade, the upstream capital cost in the value chain has risen much faster than the downstream capital cost (figure 3.3).

Figure 3.3 Up- and downstream capital cost indices



Note: The IHS CERA upstream capital cost index tracks the costs of equipment, facilities, minerals and personnel (both skilled and unskilled) used in the construction of a geographically diverse portfolio of 28 onshore, offshore, pipeline and LNG projects. It is similar to the consumer price index in that it provides a clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. Downstream index is total of refining and petrochemicals.
Source: IHS CERA (2014).

[4] For example, Tarr and Thomson (2003) argue that the depletion premium is inversely related to the size of the reserves.

McKinsey and Company found that 40 to 50 per cent of the difference between the landed cost of LNG in Japan from an Australian and Canadian project is due to cost factors that are not under the technical or managerial control of a proponent or policy maker (McKinsey and Company 2013). Such costs largely relate to the physical characteristics of the project along with its scale, scope and complexity.

The cost structure of the LNG value chain varies among and within countries, reflecting specific attributes directly and indirectly relating to location. For example, due to high labour costs and low productivity, the construction costs for Australia's LNG liquefaction projects under construction have risen to 50-60 per cent compared with the industry norm of 30 per cent of total project cost (KPMG 2014). Expectations regarding factors such as geopolitics, currency exchange rates and the regulatory and fiscal environment, which are likely to vary over the life cycle of an LNG supply project, are taken into account in forecasting the costs attributable to components of the LNG value chain.

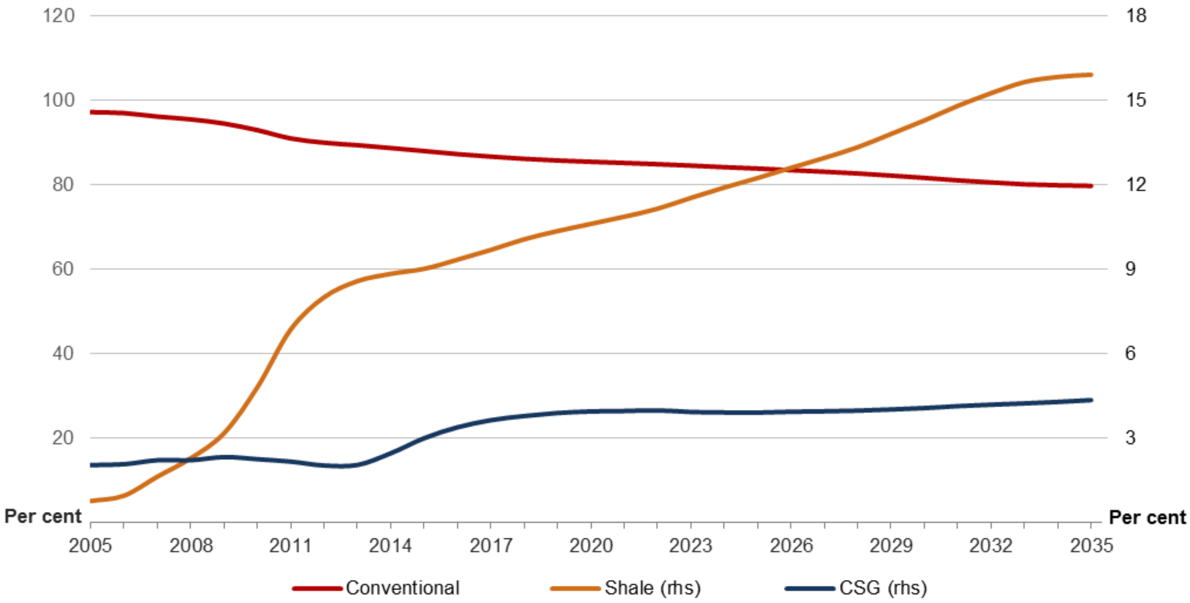
Gas production capacity

Gas production capacity refers to the maximum quantity of gas capable of being produced from current resources, taking into account any constraints and dynamics, including development of the type of gas and technology. The quantity of gas that can be produced in a given period is expressed in volumetric terms as billion cubic metres (bcm). The type of gas used may be either conventional gas or unconditional gas (such as shale gas and CSG).

The WGM projects the global production capacity of shale gas to grow faster than CSG and the production capacity of conventional gas to decline (figure 3.4). The market share of production capacity for conventional gas is projected to decline by more than 20 per cent compared to a doubling market share for CSG over the three decades between 2005 and 2035. In contrast, the market share for shale gas is projected to rise to 16 per cent in 2035 from a 1 per cent market share in 2005. The shale gas revolution has reshaped the gas market in the US and in turn is affecting global gas markets.

Despite a projected decline in the market share of the production capacity for conventional gas (from 97 per cent in 2005 down to 80 per cent in 2035), it will continue to make up the greater part of global production as shown in figure 3.4. Conversely, unconventional gas becomes increasingly important, accounting for one-fifth of the total gas production capacity by 2035.

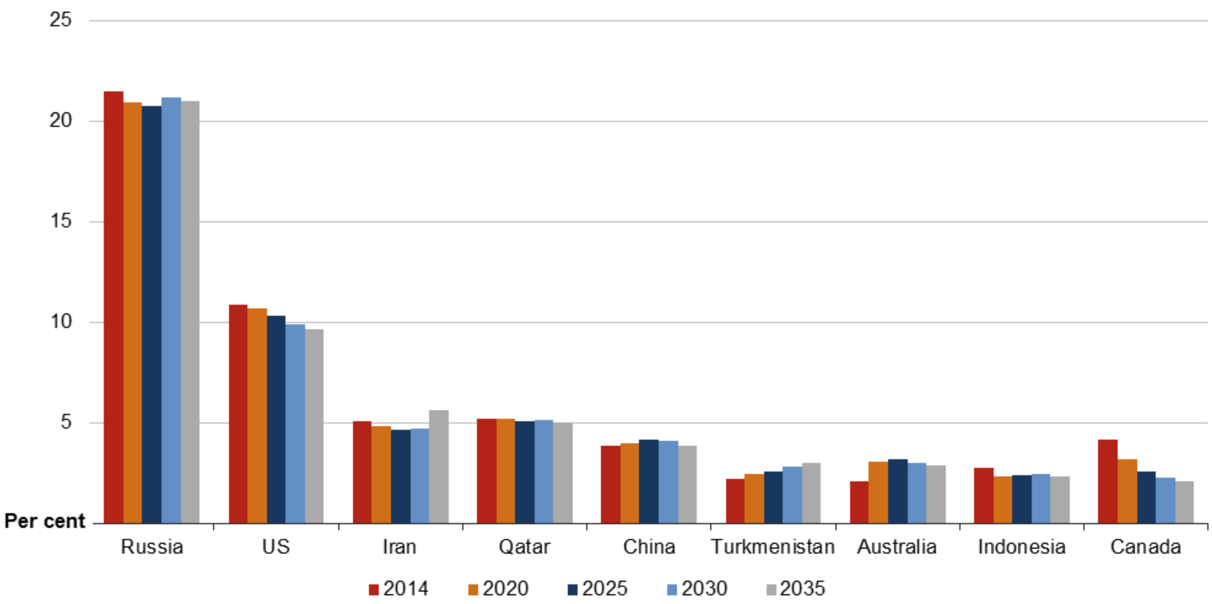
Figure 3.4 Global market shares of conventional, shale and coal seam gas



Sources: The WGM and author's calculations.

Australia along with 40 other countries produces conventional gas. Over the period from now to 2035, the WGM projects that Russia and the US together account for one-third of global production capacity (figure 3.5). This compares to about 5 per cent from Iran and Qatar, and 4 per cent from China. Canada's market share is projected to decline from currently 4 per cent to 2 per cent in 2035. Over the same period Australia's market share is projected to increase from 2 per cent to 3 per cent. In a regional context, by 2020 Australia is projected to overtake Indonesia, which is the second largest producer of conventional gas in Asia after China.

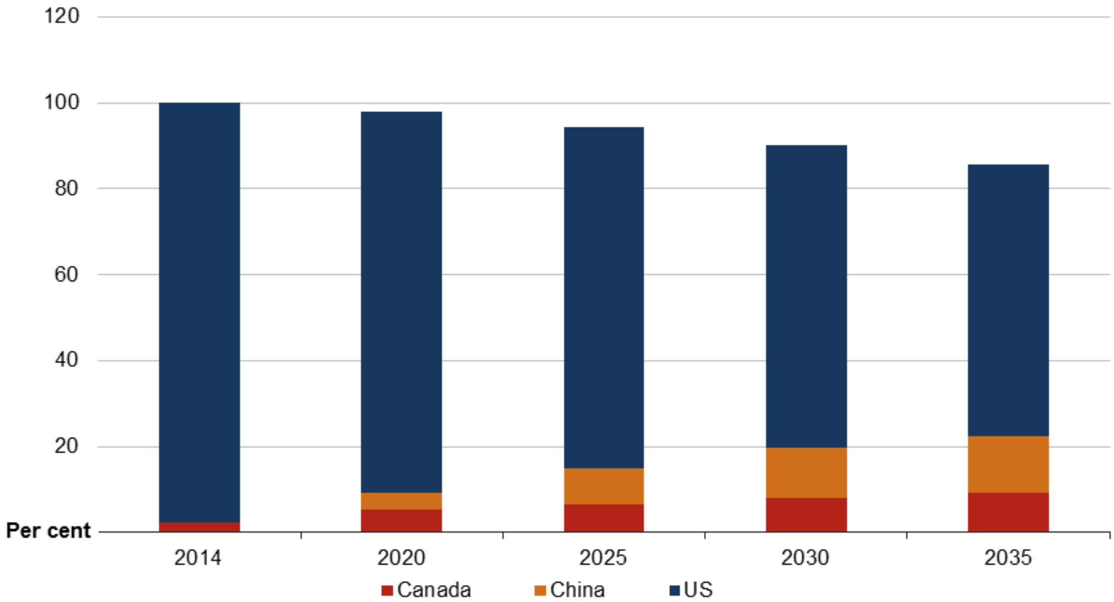
Figure 3.5 Market share of conventional gas production capacity



Sources: The WGM and author's calculations.

Of the thirteen countries producing shale gas, three (US, China and Canada) are projected to account for more than 85 per cent of total production capacity by 2035. Shale gas production is currently concentrated in the US. The US is projected to remain the key player of the shale gas production through to 2035 (figure 3.6). However, its market share is expected to decline from 97 per cent to 63 per cent over the next two decades. Over the same period, China's market share is projected to increase from 1 per cent to 13 per cent.

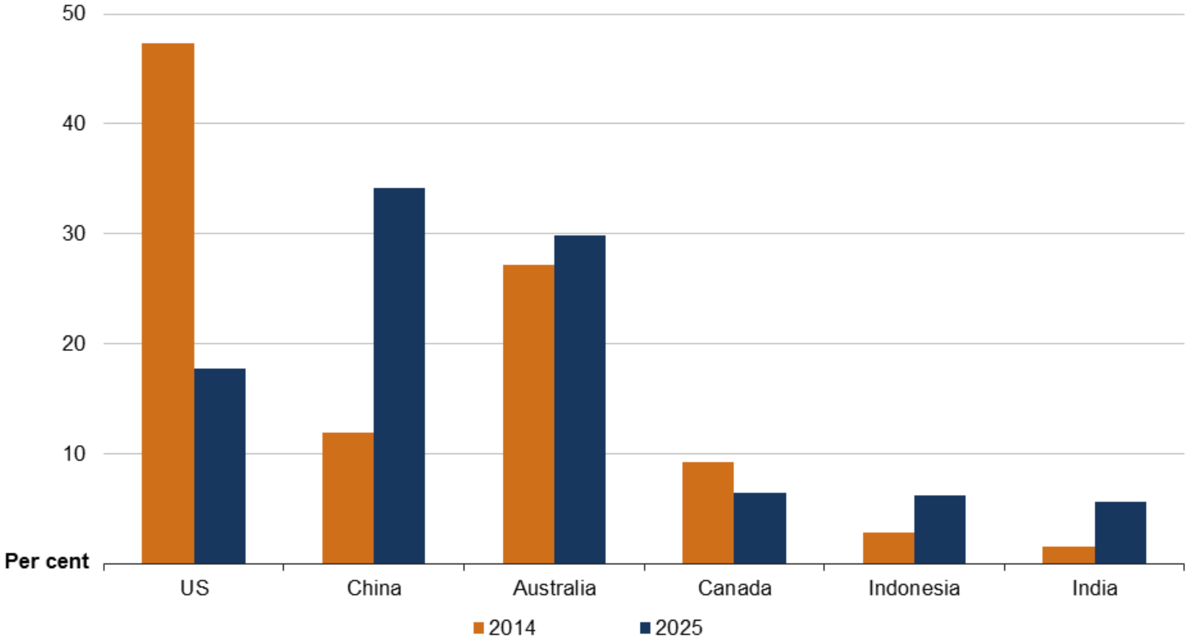
Figure 3.6 Market share of shale gas production capacity



Sources: The WGM and author's calculations.

Six countries currently produce CSG - China, Australia, US, Canada, Indonesia and India. Over the next decade the market shares of CSG production in the US and Canada are projected to decline while the market shares of both China and India triple, and Indonesia's share doubles. As a result, China and Australia are projected to account for a third of CSG production capacity by 2025. Canada, India and Indonesia combined are projected to account for 18 per cent of CSG production capacity, which is equivalent to the current capacity of the US (figure 3.7).

Figure 3.7 Market share of CSG production capacity



Sources: The WGM and author's calculations.

Cost competitiveness in gas production

The cost competitiveness of gas production in Australia is assessed by comparing the LRMC of gas production with countries and regions such as US, Indonesia and East Africa, which are expected to become new LNG suppliers to Asia in coming decades. Gas production costs consist of element such as exploration, development, drilling and completions, gas processing, gas gathering systems, water handling, taxes and royalties, and administration. In general, new (greenfield) gas developments involve large upfront investments and long lead times before first gas is produced, and have long payback periods. Such developments are more costly than adding incremental developments to producing fields, which have existing infrastructure (brownfield development).

The LRMC of gas production varies across fields and gas types (conventional gas, shale and CSG), reflecting the location of reservoirs and the quality of gas (energy content or presence of liquids and impurities).[5] Table 3.1 shows the LRMC for conventional gas production is lower than it is for CSG production. For example, in Australia, the LRMC for conventional gas production ranges from a low US$1.6 per mmbtu (Carnarvon, North West Shelf), to a medium US$2.2 per mmbtu (Cooper, Bowen-Surat) through to a high US$3.7 per mmbtu (Carnarvon, greenfield). The LRMC for CSG from the Bowen-Surat basins ranges from a low US$3.5 per mmbtu, through to a medium US$5.7 per mmbtu, to a high US$8.2 per mmbtu. For shale gas, the US is a low cost producer with a LRMC ranging from US$1.8 per mmbtu to US$3.6 per mmbtu, and China is a relatively high cost producer with costs ranging from US$3.8 per mmbtu to US$4.9 per mmbtu. The differences in LRMC reflect factors such as scales of production, technologies employed and location specific costs.

[5] Unconventional gas is less energy dense, or 'lean', compared to conventional or 'rich' gas.

Table 3.1 Selected LRMC for gas production between 2010 and 2020

	Description	US$ per mmbtu	Starting year	Capacity by 2025 (Bcm a year)
Conventional gas				
Australia West	Carnarvon	3.7	2015	35
Australia North	Browse	4.2	2017	12
Canada West	Onshore - 10000ft	2.3	2014	23
Mozambique	Rovuma Basin	3.3	2018	50
Tanzania	Offshore Tanzania	3.6	2020	33
Indonesia	East	3.7	2010	33
Malaysia	Borneo	1.8	2010	26
Russia	Siberia	3.5	2019	43
Qata	Qatargas	1.3	2010	47
PNG	All	2.6	2015	22
CSG				
Australia East	Surat-Bowen - Low	3.5	2014	24
	Surat-Bowen - Medium	5.7	2014	12
China North West	Coal Gasification	5.0	2016	30
Shale gas				
US South West	Eagle Ford - Low	1.8	2014	11
	Eagle Ford - Medium	2.0	2014	9
US North East	Marcellus - Low	1.8	2014	71
	Marcellus - Medium	2.3	2014	56
US Louisiana	Haynesville - Low	3.4	2014	16
	Haynesville - Medium	3.6	2014	13
Canada West	Horn River - Low	2.9	2014	9
	Horn River - Medium	3.0	2014	10
China South West	Sichuan - Low	3.8	2014	18
	Sichuan - Medium	4.9	2014	9

Source: The WGM.

LNG liquefaction capacity

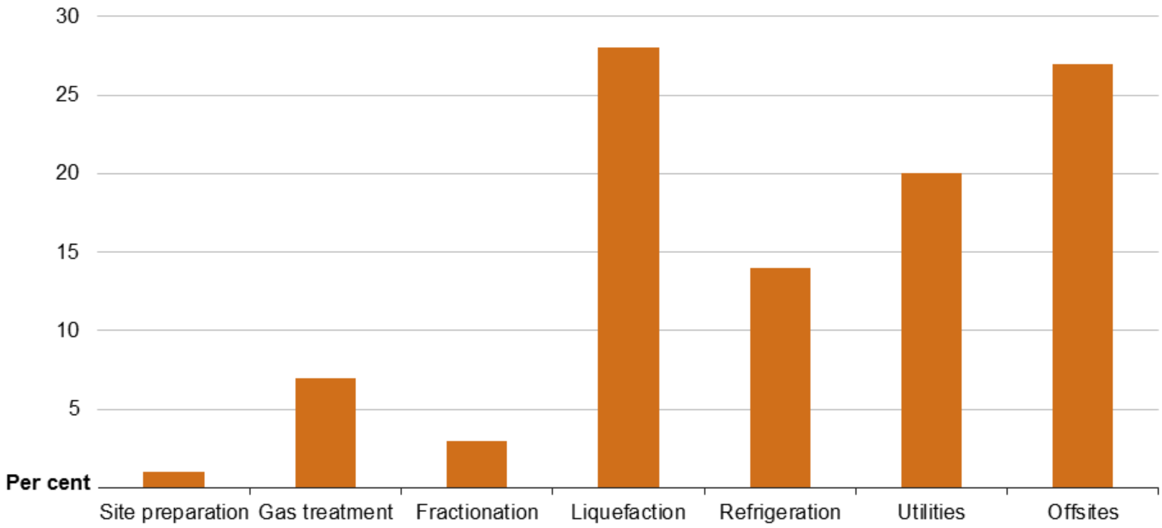
Liquefaction projects are capital intensive and therefore comprise the largest share of capital costs in the value chain. Liquefaction capacity is the nameplate capacity of the yearly output of a liquefied natural gas facility and is often expressed in terms of millions (metric) tonnes per year (Mtpa). It accounts for the constraints and dynamics of the liquefaction process, including gas quality and the technology employed. The key drivers of LNG project costs in order of significance consist of (Songhurst 2014):

- Project scope
- Project complexity
- Location (infrastructure and construction costs)
- Equipment and materials
- Engineering and project management
- Contractor profit and risk

- Owner's costs
- Contract strategy
- Currency exchange risk

While the cost of a liquefaction train (gas treatment, fractionation, liquefaction and refrigeration) is heavily dependent on the scope of the project, it is typically about 50 per cent of the total plant costs (figure 3.8) (Songhurst 2014). However, there is considerable variation in the scope of projects, which may range from solely an additional liquefaction train, to a project requiring varying types of civil and infrastructure costs relating to storage, jetty, utility systems, worker accommodation, seismic protection, soil improvement, and/or major upstream gas gathering systems. Site specific factors are a significant determinant of these broader costs.

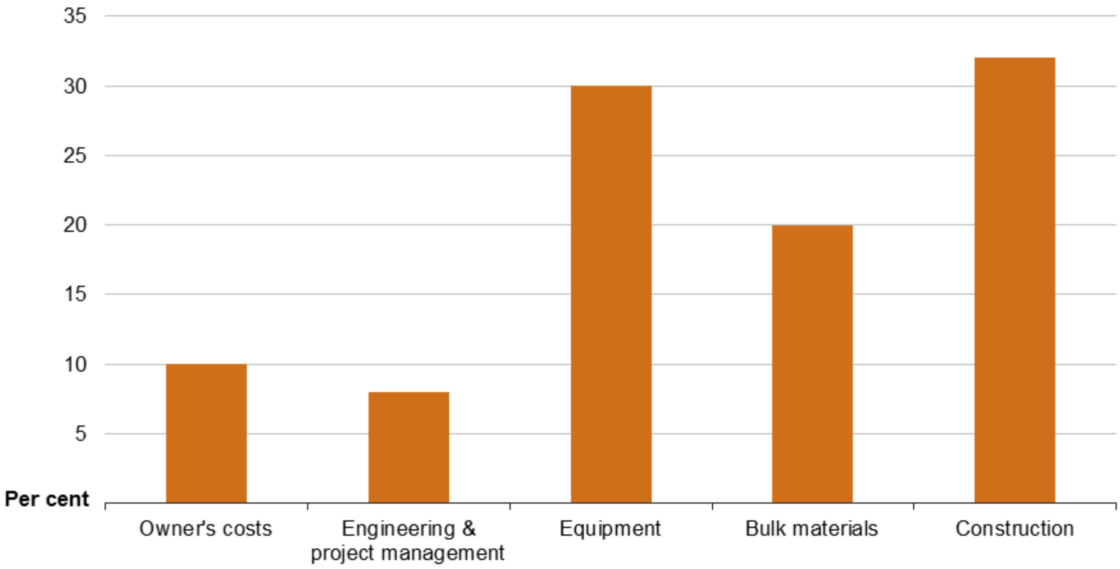
Figure 3.8 Typical total liquefaction plant cost share by expenditure area



Source: Songhurst (2014).

The main cost category for LNG projects is the construction cost (figure 3.9). Songhurst's study indicates that in general, construction cost accounts for 32 per cent of total LNG liquefaction cost followed by the equipment cost (30 per cent), the cost of bulk materials (20 per cent), owner's costs (10 per cent) and engineering and project management (8 per cent).

Figure 3.9 Typical total liquefaction plant cost share by cost category



Source: Songhurst (2014).

Across operating, under construction and proposed liquefaction facilities, costs will vary according to when the facility is built, where it is built, and the scope of the project. Older facilities have less cost to amortise because their legacy costs are lower than the costs of building new facilities. In general, a brownfield LNG liquefaction project is less expensive than a greenfield project. Cost escalation has been a particularly significant factor for greenfield projects both under construction and proposed. Recent escalations in the costs of greenfield projects are largely a result of higher materials costs, tight labour markets and mitigation costs for project delays (IGU 2014).

Brownfield projects include expansions to existing operations and those that utilise existing LNG import infrastructure. Brownfield expansions usually cost about 60 to 70 per cent of the cost of equivalent greenfield projects, as adding new trains to existing plant enables the project to take advantage of already developed infrastructure (Ledesma et al 2014). A preference for brownfield projects over greenfield projects is expected in coming years as project proponents looking to expand LNG production capacity seek to improve their economic returns by constructing additional LNG trains at existing facilities.

Currently Australia accounts for more than 50 per cent of new LNG projects under construction (table 3.2). By 2020, Australia be the world’s largest LNG exporter and will account for about 17 per cent of the global liquefaction capacity compared to around 15 per cent for Qatar and 9 per cent for Indonesia.

Table 3.2 Liquefaction capacity to 2030 (Mtpa)

	Total	Operating	Under construction	Proposed
Australia	85.9	24.1	61.8	
Qatar	77.0	77.0		
Indonesia	44.4	34.1	4.0	6.3
Russia	40.9	9.6		31.3
Malaysia	38.0	24.2	12.3	1.5
Nigeria	30.2	21.8		8.4
Algeria	28.4	23.9	4.5	
US	23.2	0.7	18.0	4.5
Mozambique	20.0			20.0
Tanzania	15.0			15.0
Canada	9.3			9.3
Total	**412.3**	**215.4**	**100.6**	**96.3**

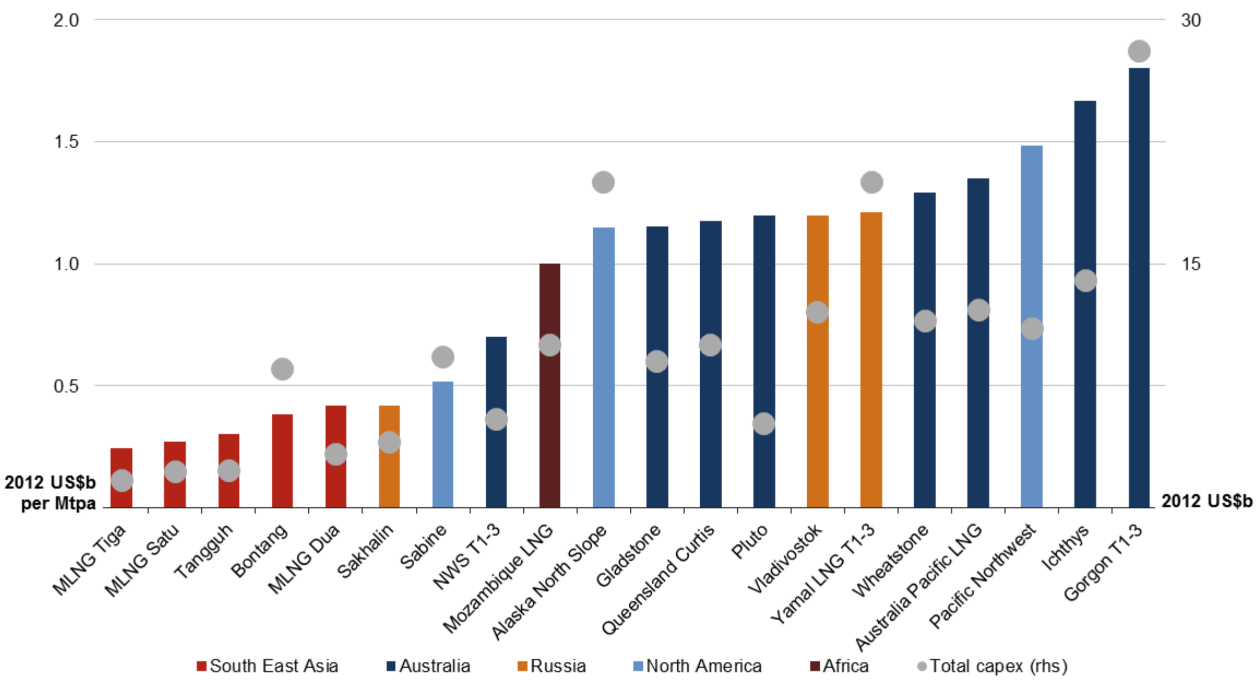
Source: The WGM and author's calculation.

Note: This excludes projects which are closed, cancelled, on hold, suspended or assumed to commence in or after 2030.

Cost competitiveness in LNG liquefaction

Figure 3.10 shows the estimated capital expenditure (capex) for liquefaction plants associated with selected LNG projects. The capex for the liquefaction plant of the Gorgon LNG project in Australia is 40 per cent higher than the capex for Alaska North Slope LNG plant in the US and Yamal LNG plant in Russia. When measured in terms of US$ billion per Mtpa the difference increases to more than 50 per cent.

Figure 3.10 Capital expenditure per mtpa for selected LNG liquefaction plants

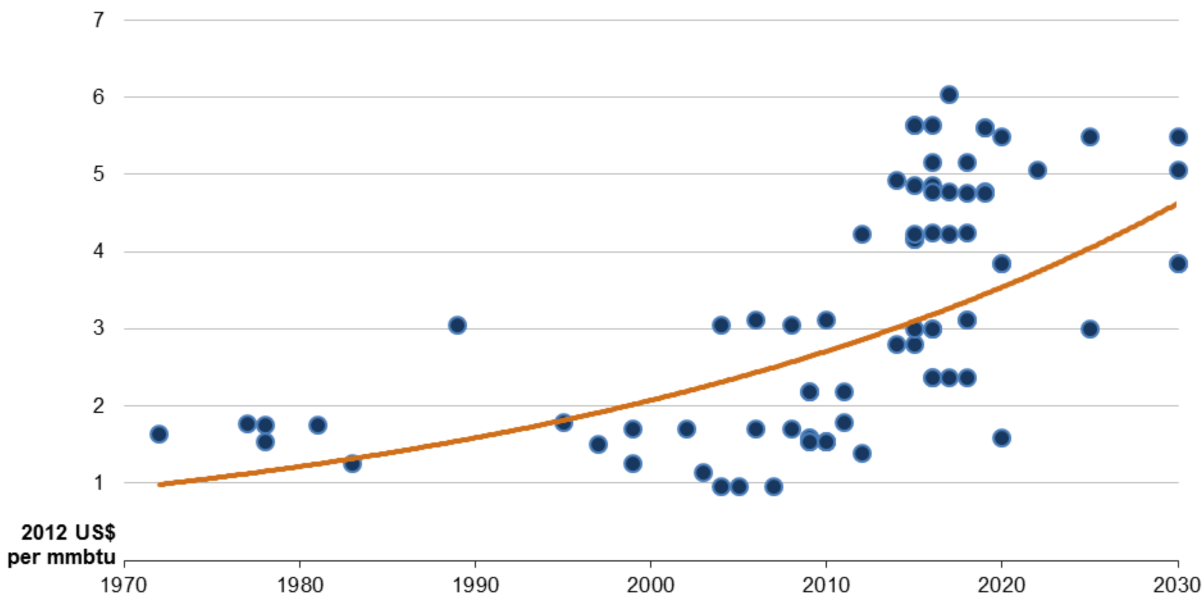


Sources: The WGM and author's calculations.

The relatively high costs of Australian LNG liquefaction plants illustrated in figure 3.10 may reflect their technical complexity and very remote locations compared to elsewhere. Costs for proposed projects may also underestimate final costs.

Figure 3.11 shows the relationship between the cost of producing a unit of output from a liquefaction facility expressed in terms of LRMC, and the start-up year of the facility. There is a trend in the growth in LRMC that is clearly increasing over time for new LNG capacity. About one-third of LNG liquefaction capacity after 2010 (including the projects that are under construction and proposed) have a higher LRMC than those built prior to 2010.

Figure 3.11 Relationship between LRMC and start-year of liquefaction



Sources: The WGM and author's calculations.

Among all the liquefaction plants under construction, the LRMC for those in Australia are higher than those in other countries. This highlights that a greenfield LNG plant constructed in Australia is more costly than a brownfield LNG project in the US that is close to existing infrastructure. For example, the LRMC for the Gorgon and Ichthys projects is 30 per cent higher than the average LRMC of the other projects, and double the LRMC of the US projects (figure 3.12). The differences in LRMC also reflect specific locational characteristics that have significantly added to the capital costs of the projects. For example, expenditure on the Gorgon project to deal with high CO_2 concentration in the gas reservoir and the siting of the LNG project on a nature reserve.

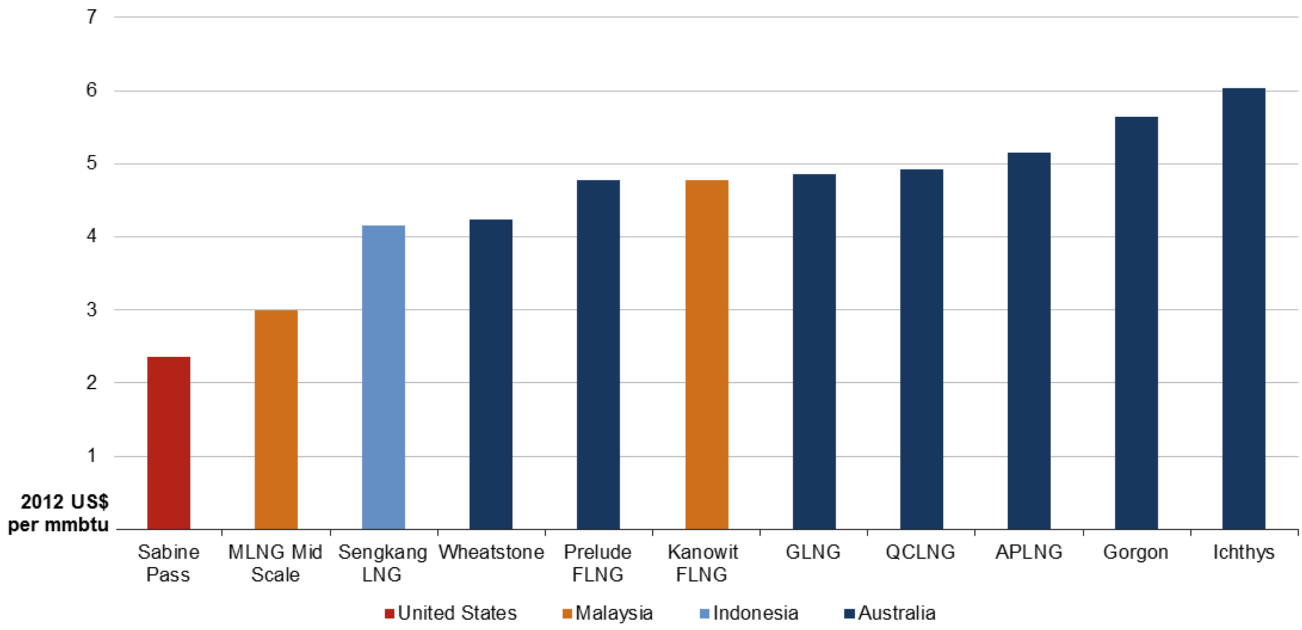
In contrast to the Australian greenfield projects, the US LNG projects are being built in industrialised areas, with established infrastructure and access to a large market for engineering and construction services. Most of the projects are conversions from existing LNG regasification terminals. This allows the projects to benefit, in the form of lower capital investment and shorter construction schedule, from the available equipment and infrastructure such as the LNG storage tanks, marine facilities and potentially some utility capacities (IEA 2014).

In the case of the US, the siting of liquefaction terminals near natural gas fields can also save transportation costs. The liquefaction plants require pipelines for feed gas. The capital cost of the pipelines[6] will be rolled into the transportation charge from wellhead to the plant, and will therefore be part of the cost to deliver gas to the liquefaction facility. With an extensive connected pipeline

[6] The pipeline cost is included in the LRMC of liquefaction in this study.

infrastructure for gas supply in the US market, foreign customers can buy gas from the market for delivery to the plant, liquefy it and ship it to overseas customers, with little or no capital investment in transmission pipelines. Based on a new business model, a tolling fee of 15 per cent is added to the Henry Hub price to cover the costs for the pipeline transport from the fields to the terminal before it is shipped as LNG (Corbeau et al 2014).

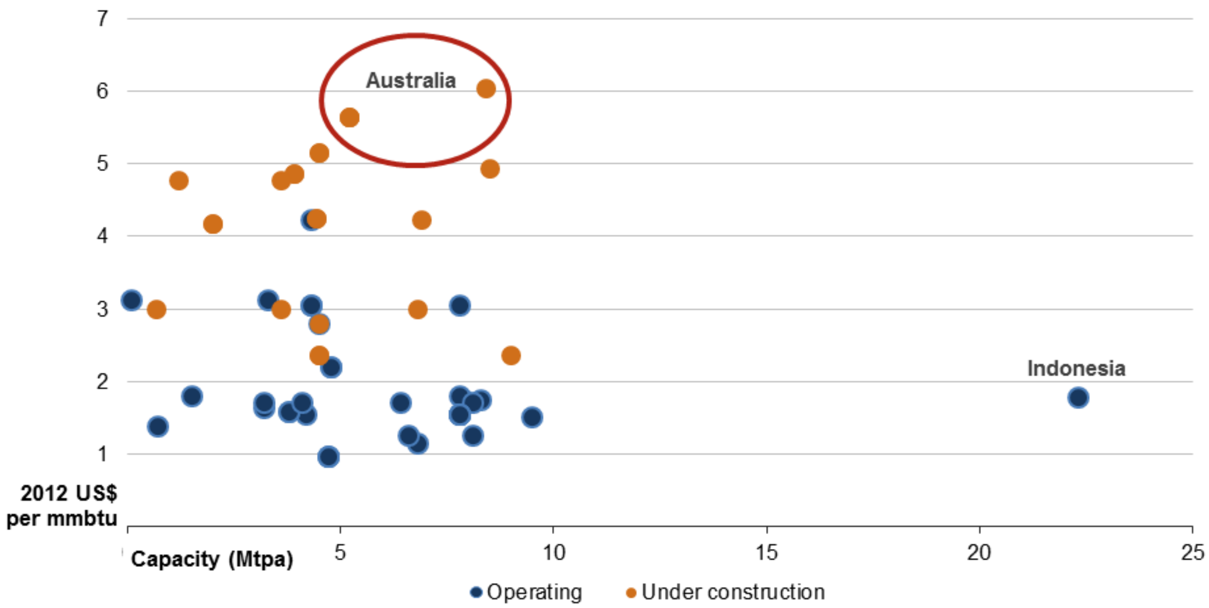
Figure 3.12 Liquefaction LRMC, selected projects currently under construction



Note: Pipelines from the field to a liquefaction plant are considered part of the liquefaction project, so are storage tanks, loading and other operational facilities.
Sources: The WGM and author's calculations.

In general the LRMC for newly constructed liquefaction plants is higher than for additional capacity at operating plants. With respect to liquefaction capacity, the LRMC of Australia's LNG projects are highest (such as Ichthys and Gorgon) among those projects under construction. While the LRMC of LNG liquefaction is relatively lower for projects which have larger capacity and are operating, this relationship does not necessarily hold for larger capacity new projects, particularly in Australia (figure 3.13).

Figure 3.13 Liquefaction LRMC against capacity: operating vs. under construction



Notes: Pipelines from the field to a liquefaction plant are considered part of the liquefaction project, so are storage tanks, loading and other operational facilities. Projects that are assumed to start after 2030 are not included.
Sources: The WGM and author's calculations.

Shipping capacity

Shipping connects LNG producers to global and regional gas users. Current key shipping routes include the Middle East to Asia, Australasia and South East Asia to Northern Asia, and Africa to Southern Europe. The LNG shipping market has increased rapidly over the last decade, driven by rising LNG demand and growth in global liquefaction capacity. LNG shipping capacity is characterised by the quite cyclical order and delivery of LNG vessels (Timera Energy 2014).

The main drivers for LNG shipping capacity are LNG demand and average journey time, and the proportion of ballasted (un-laden) voyages (Timera Energy 2014). Greater LNG demand means higher demand for shipping capacity. Longer average voyages and a higher proportion of ballasted voyages require more shipping capacity to move a given volume of LNG. The amount of shipping capacity required reflects trade flows based on both contracted LNG and uncontracted LNG. Over the last few years there has been an increasing trend in the share of uncontracted LNG is a result of the growth in trading of sport cargoes and the evolution of LNG portfolio optimisation.

Today most new LNG carriers under construction carry 120 000 to 150 000 cubic metres of LNG. Obviously, the bigger the ship, the fewer trips needed to deliver a given quantity of gas. Vessel capacities are matched to the LNG regasification terminal to deal with capacity constraints and port characteristics. With respect to shipping LNG to Asia, the larger size of LNG carriers may reflect the long distance (such as from Canada) or volume of LNG being exported (such as from Russia to Japan) (table 3.3). Although not shown in table 3, there are very large vessels with a capacity of up to 266 000 cubic meters shipping LNG from Qatar to Chinese Taipei.

Table 3.3 Average vessel size of LNG carriers to the Asian market, cubic metres

	Japan	China	India	Korea
Russia	147 200	138 000	138 000	133 222
Canada	145 000	145 000	145 000	145 000
Qatar	143 065	148 212	136 026	137 044
US (except Alaska)	138 000	138 000	138 000	138 000
PNG	138 000	138 000	138 000	138 000
Australia	135 466	147 000	138 000	138 000
Indonesia	116 099	155 000	155 000	127 891
Malaysia	112 553	113 936	113 936	126 063

Source: The WGM.

Cost competitiveness in LNG shipping

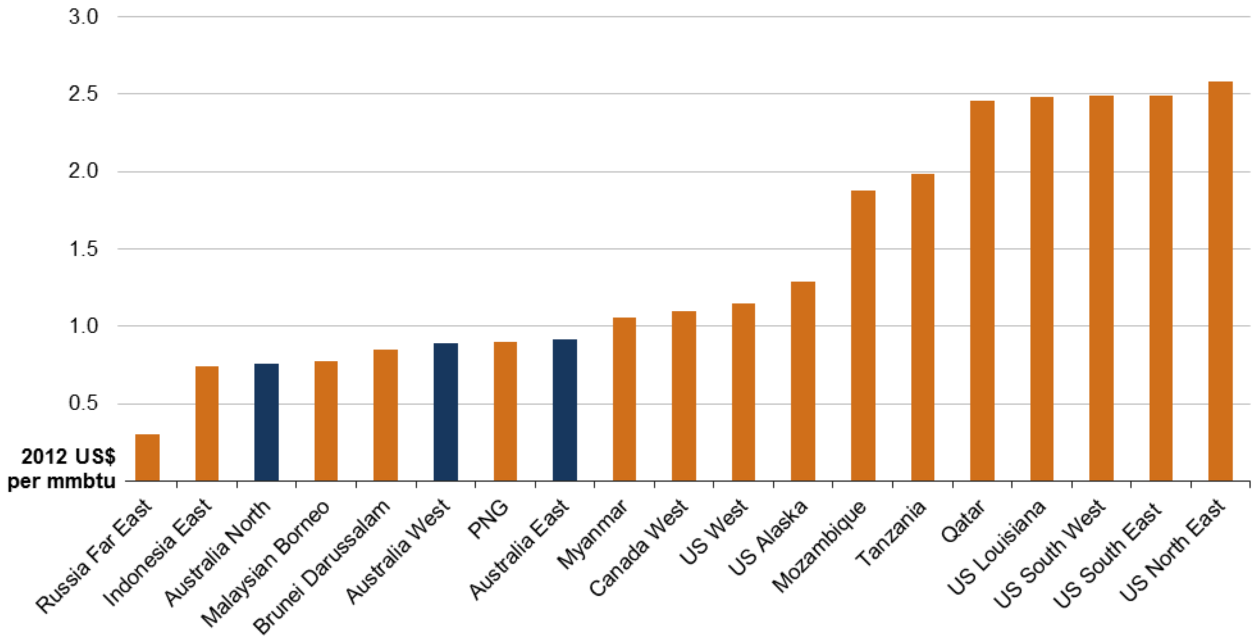
LNG shipping costs affect LNG landed costs and, hence, trade flows. Shipping cost is a key driver of the value created by moving gas between locations and the price spreads between regional gas markets (Timera Energy 2014). With respect to contracted LNG, whether the supplier or buyer pays for the shipping cost depends on the specifics of the contract. In a destination ex-ship (DES) contract, it will be the supplier who incurs all the shipping cost. In a free on board (FOB) contract, the buyer covers the shipping cost. Large LNG portfolio players can reduce shipping costs by optimising their tanker fleet (Timera Energy 2014).

Estimates of the LRMC of shipping LNG is based on trip time, including distance (nautical miles), voyage and days in port plus contingencies, and the LNG delivered per trip based on ship size and other adjustments, and port and canal charge.[7] Given the assumptions of the WGM, shipping LNG from Australia to Asia is cost competitive (figure 3.14). The LRMC for shipping LNG to Japan is lower from Australia's north than from Malaysia, lower from Australia's west than from PNG, and lower from Australia's east than from the US, Canada and Western Africa. The LRMC of shipping from Canada to Japan is more than 20 per cent higher than it is from Australia's west and the LRMC from the US is about three times the cost from anywhere in Australia.

Under the scenario considered in this analysis, US cargos of LNG to Asia are expected to travel from the Gulf Coast through the expanded Panama Canal, which is due for completion in 2016. The shipping cost from Canada is cheaper than the US, as it takes three days less to deliver LNG to Japan from British Columbia compared with delivery from the US Gulf Coast, and there is no need to incur charges for using the Panama Canal.

[7] Assumptions for shipping costs are presented in Appendix 3a.

Figure 3.14 Shipping LRMC, from export origin to Japan in 2014



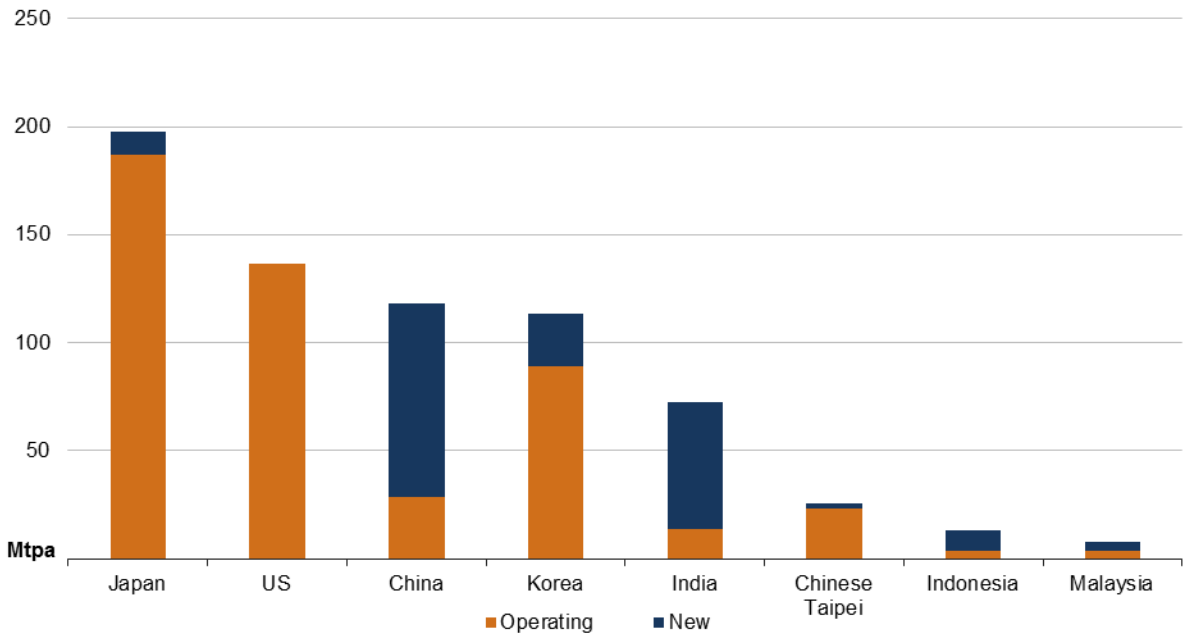
Sources: The WGM and author's calculations.

LNG trade in the Asian market

Asia possess the world's largest LNG importing countries (Japan and Korea) and two of the world's fastest growing gas markets (China and India). Both China and India have high economic growth rates and a low share of gas in the primary energy mix, and both have domestic gas production and are LNG importers. China is also increasing imports of pipeline gas mainly from central Asia and Russia. Asia is and will be a key market for LNG imports over coming decades. While growth in demand for LNG from Japan and Korea is projected to decline, these countries will continue to dominate the global market share of LNG imports. The focus on growth in LNG demand in the Asian region moves to India and China.

Changes in regasification capacity may be used as a proxy for potential changes in LNG demand. Total regasification capacity for seven Asian countries (Japan, China, Korea, India, Chinese Taipei, Indonesia and Malaysia) is projected to account for more than 50 per cent of the global market share by 2030. In response to an increase in the domestic consumption of natural gas, it is projected that Indonesia will triple and Malaysia will double its regasification capacity respectively by 2030 (figure 3.15).

Figure 3.15 Regasification capacity, operating and new, by 2030



Note: New includes under construction and proposed to operate by 2030.
Sources: The WGM and author's calculations.

The main countries supplying the increase in projected LNG demand from Japan, China, India and Korea by 2025 are presented in table 3.4. Almost all countries supplying LNG to the Asian market supply Japan. Indonesia and Qatar are key nations supplying LNG to China's east. Malaysia, PNG and Australia are key suppliers to China's south.

Table 3.4 Key LNG suppliers to China, Japan, India and Korea, contracted by 2025

Origin/Destination	China East	China South	China North	Japan	India	Korea
Asia-Pacific						
Indonesia East	✓			✓		
Malaysia Borneo		✓		✓		
PNG		✓		✓		
Brunei Darussalam						✓
Australia West		✓	✓	✓		
Australia East		✓		✓		
Australia North				✓		
North-America						
US South West				✓		✓
US Louisiana				✓	✓	✓
US North East				✓	✓	
Canada West				✓	✓	
Middle-East						
Qatar	✓			✓	✓	✓
Oman				✓	✓	✓
UAE				✓	✓	
Russia Far East				✓		✓

Source: The WGM.
Note: The information is for contracted LNG only.

Given differences in the source and extent of supply competition it is useful to focus on the cost competitiveness of Australia's LNG exports to both Japan, which is the largest LNG buyer, and China, which is projected to be the significant source of growth in LNG demand in the Asian market.

Cost competitiveness of Australia's LNG exports to Japan

Australia is projected to continue to be the largest LNG exporting country to Japan. As the liquefaction projects currently under construction come online Australia will account for just over a third of the market share of total LNG exports to Japan by 2020 (table 3.5). LNG exports from the US to Japan are projected to increase to a third of Japan's total LNG demand by 2030 from a fifth market share in 2020.

Table 3.5 Key LNG suppliers and LNG exports to Japan

Export origin	**2015 (bcm)**	**2020 (bcm)**	**2030 (bcm)**
Indonesia East	11.2	6.7	10.4
Malaysian Borneo	17.0	6.3	4.2
Russia Far East	12.0	9.2	4.4
Qatar	11.5	10.8	1.4
UAE	7.0	4.1	0
PNG	2.5	3.8	11.1
Australia West	20.7	26.2	27.6
Australia East	4.4	7.0	7.5
Australia North	3.8	9.2	6.3
Australia's share (%)	**24.2**	**35.1**	**33.6**
US South West	0	12.1	9.2
US Louisiana	0	11.3	29.0
US North East	0	3.0	3.0
US's share (%)	**0**	**21.8**	**33.4**

Source: The WGM and author's calculation.
Note: The information is for contracted LNG.

Based on the aggregated cost of the Asian LNG market's value chain, Australia's LNG exports to Japan are less cost competitive than other exporting countries, including new rivals such as the US (shale gas) and PNG (conventional gas). This is despite Australia being cost competitive in shipping. Table 3.6 shows that the aggregated cost of the LNG value chain for LNG exports from Australia's West (e.g. Gorgon) to Japan is expected to be more than 30 per cent higher than exports from PNG. Both countries' LNG is based on conventional gas. It also shows that the aggregated cost from Australia's east (CSG) is expected to be more than 40 per cent higher than from the US Louisiana (shale gas) based on the medium cost for each type of unconventional gas. The higher cost for Australia's LNG exports is due to relatively higher cost of gas production and liquefaction compared to competitors.

Table 3.6 Comparison of delivered costs by LNG value chain component to Japan

Export origin	Gas production (US$/mmbtu)	Liquefaction (US$/mmbtu)	Shipping (US$/mmbtu)	Total cost (US$/mmbtu)
Malaysia Borneo (*Asia Pacific*)	1.84	4.20	0.71	6.75
PNG (*PNG LNG*)	2.62	4.23	0.82	7.67
US Louisiana (*Sabine Pass*), shale				
low gas cost	3.36	2.36	2.27	8.00
medium gas cost	3.62	2.36	2.27	8.25
high gas cost	4.01	2.36	2.27	8.64
Indonesia East (*Sengkang LNG*)	3.67	4.80	0.68	9.15
Australia West (*Gorgon*)	3.70	5.64	0.84	10.18
Australia North (*Ichthys*)	4.16	6.00	0.70	10.86
Australia East (*APLNG*), CSG				
low gas cost	3.54	5.15	0.84	9.53
medium gas cost	5.72	5.15	0.84	11.71
high gas cost	8.22	5.15	0.84	14.21

Source: The WGM.

Note: The shipping cost is estimated as LRMC in 2020. There could be additional cost of US$1.5 per mmbtu for infrastructure in PNG LNG to the total of US$9.17 per mmbtu that will be more than 10 per cent less than the cost of Gorgon.

Cost competitiveness of Australia's LNG exports to China

China is projected to become one of the largest importers of LNG in the next decade, and Australia's share of its total LNG imports increases from 23 per cent in 2015 to more than 50 per cent by 2030. China's south is the major source of new LNG demand and supplied in the main from exports based on CSG in Australia's east and conventional gas in Australia's west (table 3.7). An increase in imports of natural gas from pipelines is expected to meet gas demand in China's industrial heartland in the north.

Table 3.7 Key LNG suppliers and exports to China

To	From	2015 (bcm)	2020 (bcm)	2030 (bcm)
East	Indonesia East	3.0	18.3	4.9
	Qatar	3.5	3.5	3.5
South	Malaysia Borneo (*new*)	0	16.9	0
	PNG (*new*)	0.6	2.3	2.3
	Qatar	2.3	2.3	2.3
	Australia West	3.4	3.8	4.2
	Australia East (*new*)	1.0	13.0	13.0
North	Australia West (*new*)	0.7	2.6	2.6
Australia's share (%)		***23.1***	***28.2***	***50.9***

Source: The WGM and author's calculation.

Note: The information is for contracted LNG.

Although Australia's LNG projects under construction in the east and west are less cost competitive for exporting to China's south compared to projects under construction in Malaysia and PNG (table 3.8), supply from Malaysia is projected to decline over time and the new supply from PNG will be relatively small.

Table 3.8 Comparison of delivered costs by LNG value chain component to China's south

Export origin	Gas production (US$/mmbtu)	Liquefaction (US$/mmbtu)	Shipping (US$/mmbtu)	Total cost (US$/mmbtu)
Malaysia Borneo (*Asia Pacific*)	1.84	4.20	0.38	6.42
PNG (*PNG LNG*)	2.62	4.23	0.81	7.66
Australia West (*Gorgon*)	3.70	5.64	0.64	9.98
Australia East (*APLNG*), CSG				
low gas cost	3.54	5.15	0.85	9.54
medium gas cost	5.72	5.15	0.85	11.72
high gas cost	8.22	5.15	0.85	14.22

Source: The WGM and author's calculation.

Note: The shipping cost is estimated as LRMC in 2020. There could be an additional cost of US$1.50 a mmbtu for infrastructure in PNG LNG, which would increase total cost to US$9.16 a mmbtu, slightly lower than the total cost of LNG from Australia East with low gas cost for CSG.

Conclusion

This analysis on the cost competitiveness of Australia's LNG supply to the Asian region was based on an assessment of the LRMC of components of the LNG value chain (gas production, liquefaction and shipping) derived from the base-case data and assumptions of the WGM. From this analysis there are several insights.

Australia's status as a producer of both conventional and unconventional natural gas in the Asian region is projected to grow in importance over time. While in general the production cost of conventional gas is less expensive than for unconventional gas, such as CSG, Australia faces costs pressures in the production of both sources of gas. The cost of producing conventional gas is higher in Australia than for its competitors and CSG is more expensive to produce than shale gas in North America.

Australia is also a high cost producer of LNG. The cost of LNG liquefaction is higher in Australia than elsewhere, mainly due to factors specific to projects such as their scale, scope and location. In contrast to the gas production and liquefaction, Australia is cost competitive in shipping LNG to customers in Asia, particularly compared to shipping from North America.

When the value chain costs are considered jointly, despite the competitive disadvantage of new LNG projects in Australia, based on existing projects and those under development Australia continues to be the country with the major share of exports to Japan.

China is projected to become one of the largest importers of LNG in the next decade, and Australia's share of its total LNG imports is projected to more than double between 2015 and 2030. This outcome is due to competing LNG exporters in the region facing specific constraints in increasing their supply to China.

There are several important factors not captured in the simplified approach adopted that may affect the cost competitiveness of Australian projects. The first relates to historical trading relationships and geopolitical considerations, which may be highly valued by some LNG customers. Australia has developed a very good reputation as an LNG producer based on its large gas reserves, low sovereign risk, regulatory certainty, proximity to the largest LNG market, reliability, and extensive contact and market experience. Furthermore, some countries may give preference to diversifying their sources of supply, or excluding particular sources of supply over the direct financial cost of LNG.

The second factor concerns challenges specific to Australia as an LNG producer. Australia is becoming recognised as a high cost location for investment in LNG projects due to the complexity and scope, remote locations, high construction costs and exposure to extreme weather events of many of the projects. However, both Industry and government are working towards reducing the costs of projects. Industry is doing this through engineering/technology solutions and improving the productivity of both labour and project management. Government is contributing through reviewing the industrial relations framework and adopting more efficient and effective regulations. The implications of these initiatives on the cost of future projects remain to be seen.

There is another factor that deserves mention that may have a significant effect on upstream sector costs and even the viability of future LNG liquefaction projects. It is becoming increasingly recognised that gas producers and project proponents need to gain the community's social licence to operate. Without the community's trust and support, project costs may become prohibitively high in what is likely to become a very competitive environment for the supply of LNG.

As this analysis suggests, competition for LNG supply into the Asian region is likely to remain strong for some time. In light of the competitiveness and cost challenges for new LNG supply into the Asian region, the challenge for Australian LNG project proponents and those elsewhere will continue to be ensuring projects are developed and delivered at the lowest cost possible.

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Appendix 3a Shipping cost assumptions

Ship Speed (knots)	19
Trip Time Contingency %	0.1
Port days (loading)	1
Port days (unloading)	2
Waiting days in harbour waters	0.1
LNG Ship Delays	3.2
Ship loading rate, %	1
LNG evaporation, % per day	0
Residual LNG volume in tank	0.1
Conversion cm LNG to cm gas	615
Bunker fuel consumption - en route (t/day)	170
Bunker fuel consumption - in port (t/day)	40
Port Charges $/day	545
Panama Charge $/mcm	18
Panama Canal Expanded from (year)	2016
Panama Canal Expanded from (quarter)	1
Extra round trip days if Panama diversion	24
Suez Charge $/mcm	15.5
Block Charge $/mcm	1000 *(a)*

Source: The WGM.

Notes: (a) High cost is used to ensure no flow on blocked routes (e.g. the routes from Libya). Other assumptions include bunker price US$/t per year, for example it is US$559.77/t in 2014.

4 GLOBAL LNG OUTLOOK

Introduction

Australian LNG producers are facing increasing competition from new entrants into the Asian market. Although the outlook for LNG market conditions is veiled with uncertainty, it is important to understand some of the key factors likely to drive outcomes over the medium to longer terms.

This chapter presents an outlook for global LNG demand and supply based largely on projections from the latest reference case of the Nexant World Gas Model, which has been adjusted in line with BREE's assumptions where relevant. The chapter begins with an historical overview of the global LNG market, then presents a medium-term outlook for the LNG supply and demand to 2020 and finally discusses the market conditions for LNG out to 2030.

The LNG market to 2014 – *50 years of growth*

Basic elements of the global LNG market

The global LNG market currently supplies about 9 per cent of world demand for natural gas, with international pipelines supplying approximately another 20 per cent. The majority (71 per cent) of gas demand is supplied by indigenous production, owing to the high costs of gas transportation between countries, with LNG being at the high end of the cost curve given the complexities and capital intensive nature of LNG liquefaction and delivery.

The commercial LNG market has to date been dominated by bilateral contracts between suppliers and consumers. The contracts are long-term (generally up to 20 years) and can impose take-or-pay terms on the buyers. These contractual terms help to mitigate the revenue risks on producers and incentivise the large capital investments required. It is not uncommon for customer nations to also take equity in the projects as a way to further mitigate and diversify risk for the producers.

The international LNG market is primarily driven by an imbalance between indigenous supply and demand since local supply, if available at reasonable cost, will always be preferred to imports. LNG imports are feasible if there is a lack of adequate indigenous resources, or if it is impossible or undesirable to construct international pipelines (Japan, South Korea and Chinese Taipei which currently take 60 per cent of world LNG production, are good examples of this situation). On the supply side, LNG exports allow for the exploitation of otherwise stranded gas resources where there is insufficient local demand (for example Trinidad & Tobago, Nigeria, PNG, and the Australian North West Shelf, Browse and Bonaparte offshore basins).

In other cases, LNG is used as a supplement to indigenous production and pipeline imports. This is the case, for example, with LNG imports into Europe and China, where LNG imports are a relatively small part of total domestic demand. In these markets, the volume of LNG demand is highly sensitive to competition from pipeline suppliers, and/or increases in indigenous production, which makes predicting LNG demand in these countries extremely difficult and uncertain.

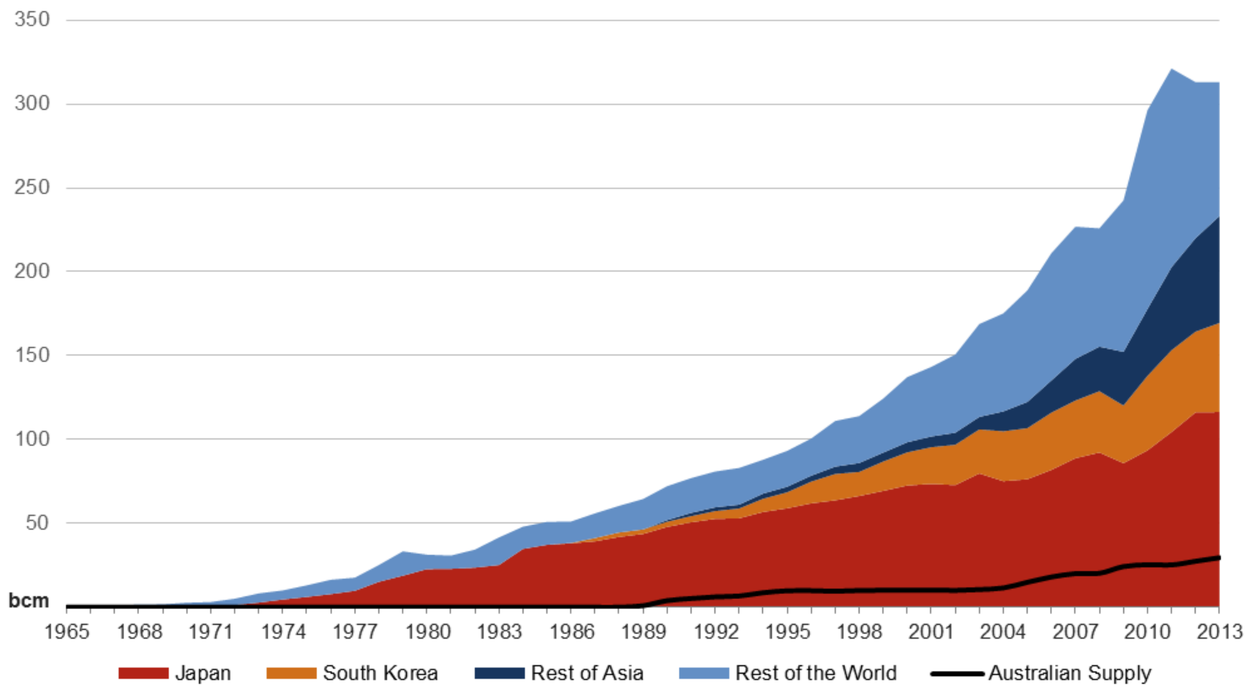
Given the potential competition between indigenous production, pipeline imports and LNG imports, price expectations will always be the key factor in determining the demand for LNG.

Historical overview – strong growth since 1969

The global LNG market began 50 years ago on 12 October 1964, when a small shipment of LNG from Algeria was delivered to Canvey Island in the UK aboard the dedicated LNG carrier, the *Methane Princess*. France commenced imports one year later, followed by Japan in 1969. By 1970, almost 7 Mt of LNG had been shipped from Algeria, Libya and the USA. Since then the expansion of the LNG trade has been rapid, growing at an annual rate of 11.7 per cent a year to reach approximately 230 million tonnes per annum (Mtpa) by 2013. This is approximately 9 per cent of total world demand for natural gas.

Figure 4.1 shows the growth of LNG imports over the past 50 years, broken down by the main customer countries. The contribution from Australian exports is also shown, supplying close to 8 per cent of global imports since 1989.

Figure 4.1 Global LNG imports



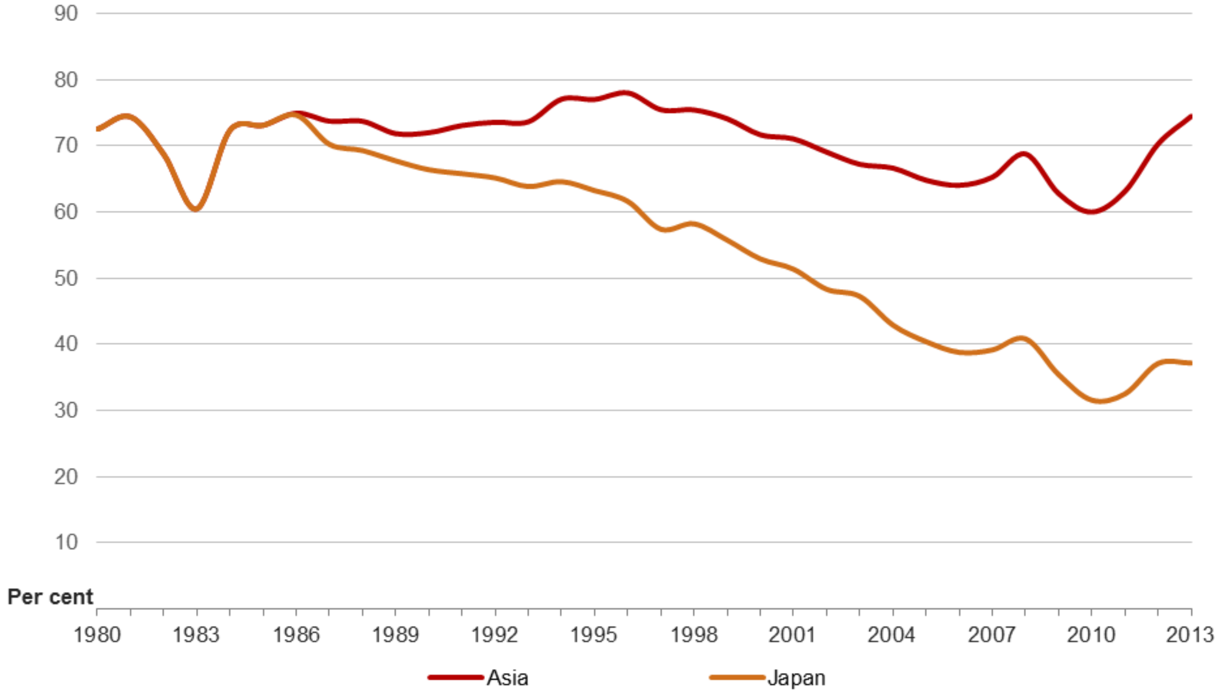
Sources: BREE and Petroleum Economist.

As of 2014, there were 30 countries importing LNG from 19 exporting countries, and this number is expected to grow, with Poland commencing imports in 2015. There are also 357 operating LNG carriers, with 127 more ships currently on order.

Asia takes 70 per cent of global trade

Figure 4.2 shows the share of Asian trade in the global market. Asia has been the dominant destination of LNG deliveries since 1980, absorbing around 70 per cent of global production. Japan has always been the dominant market for LNG, and although it has declined from its previous high of 70 per cent of global imports, it is still by far the largest single destination country with 37 per cent of the world market.

Figure 4.2 Asia's share of global consumption

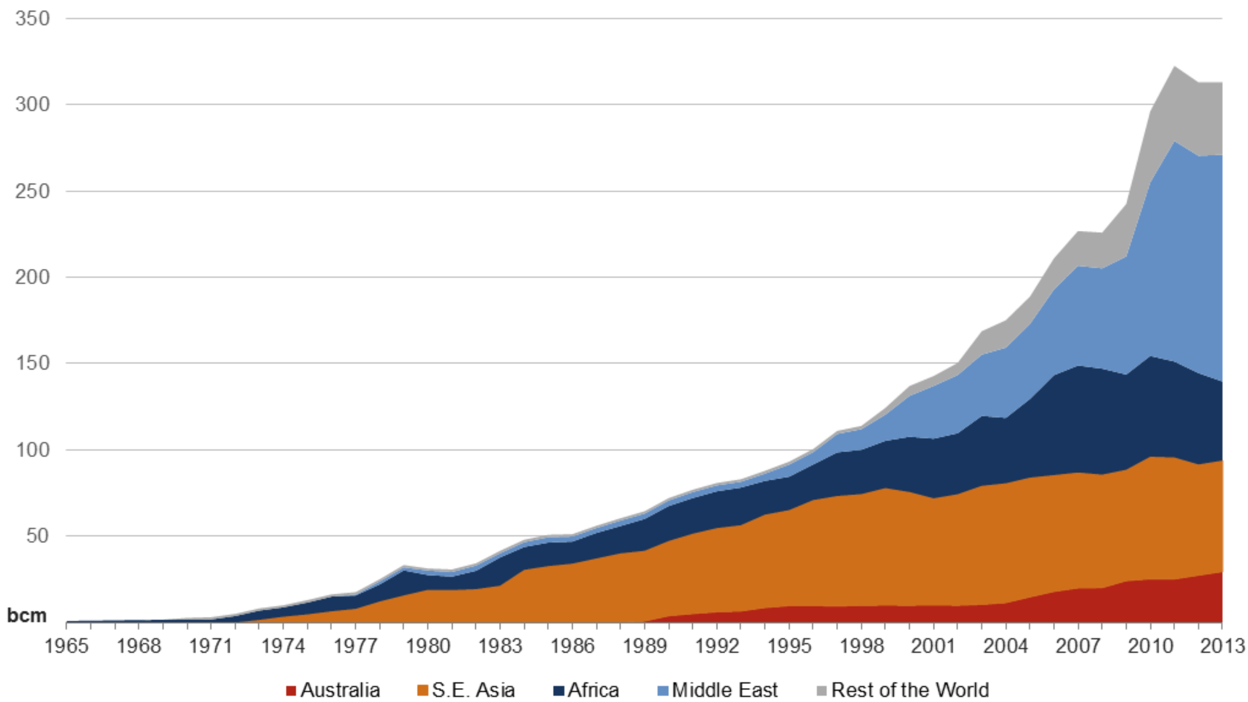


Sources: BREE and Petroleum Economist.

But the LNG supply market is volatile

Figure 4.3 shows the main sources of LNG supply to the global market.

Figure 4.3 Global LNG production



Sources: BREE and Petroluem Economist.

The countries supplying LNG are quite diverse, ranging from large scale oil and gas producers such as Qatar in the Middle East, to small island nations such as Trinidad & Tobago, which have large but otherwise stranded gas reserves.

The main suppliers of LNG have traditionally been South East Asia (Brunei, Indonesia and Malaysia) and Africa (mainly Algeria, Nigeria and Egypt). However, the Middle East (mainly Qatar) has recently become the dominant supplier, with output more than doubling since 2008 to reach 42 per cent of global supply in 2013. There has also been significant growth from a range of other suppliers.

Australia began exports in 1989 from the North West Shelf off Karratha in Western Australia. Since then, Australia has become a growing player in the LNG production industry, supplying approximately 8 per cent of global imports on average.

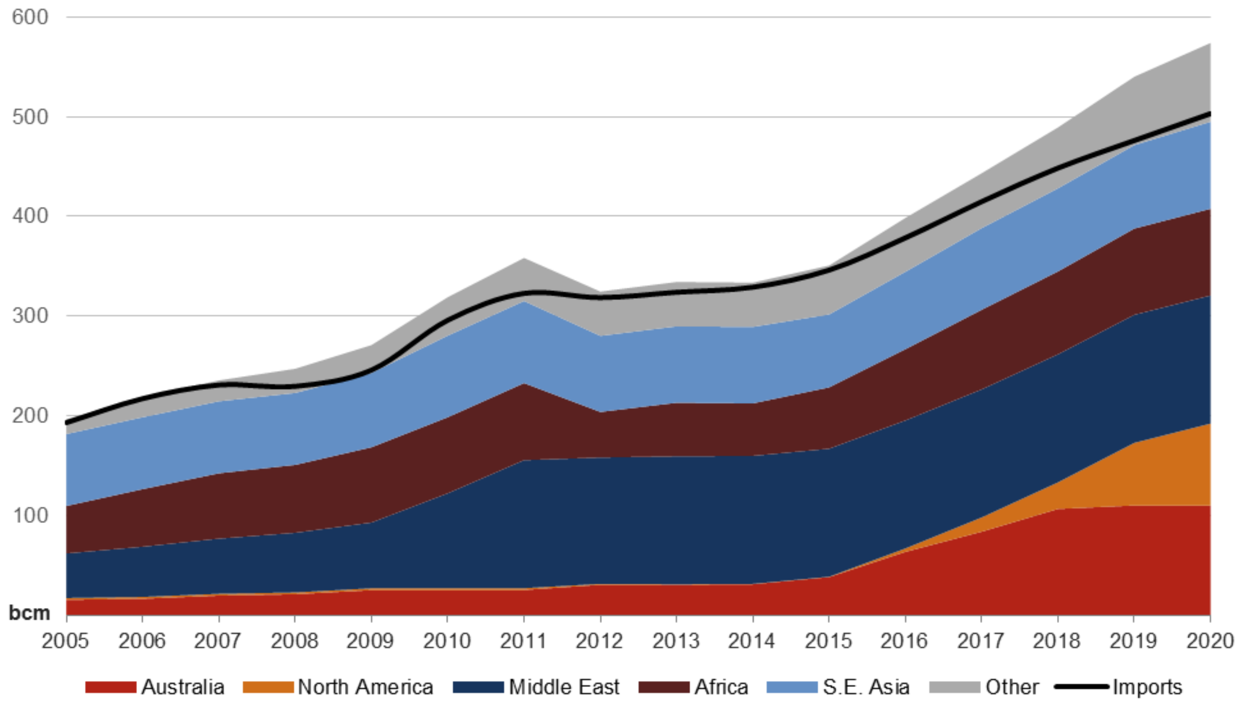
The Australian LNG industry is currently investing approximately $200 billion in LNG production, which once completed will have increased capacity from 24 Mtpa to 86 Mtpa. Australia will overtake Qatar by 2018 to become the largest exporter of LNG in the world.

LNG supply to 2020 – *Australia and the US dominate new supply*

The global LNG market is expected to expand rapidly to 2020, and deliveries should reach 500 billion cubic metres (bcm) (370 Mtpa) by 2020, a growth rate of 6.5 per cent a year over the period from 2013. Much of this growth is assured by the contracts already entered into between suppliers and consuming countries or portfolio traders, and by the extent of investment already committed to LNG liquefaction and regasification facilities.

Figure 4.4 shows the anticipated growth in LNG production capacity to 2020 and the forecast of total LNG imports over this period.

Figure 4.4 LNG imports and capacity by country 2005-2020



Sources: BREE and Nexant.

Current conditions are very tight

Since 2012 the LNG market has experienced extremely tight market conditions (despite the more than doubling of Qatari liquefaction capacity between 2008 and 2011). These tight conditions have contributed to very high spot prices, particularly in the Asian market, and are due to a number of factors including:

- the significant and unanticipated growth in Japanese LNG imports due to the Fukushima disaster in March 2011 (adding an estimated 20 bcm to LNG demand)
- the fall in global effective liquefaction capacity in 2012 due to technical and supply problems in a number of African countries, including Egypt, Algeria, Angola and Nigeria (and to some extent due to supply difficulties in Indonesia)

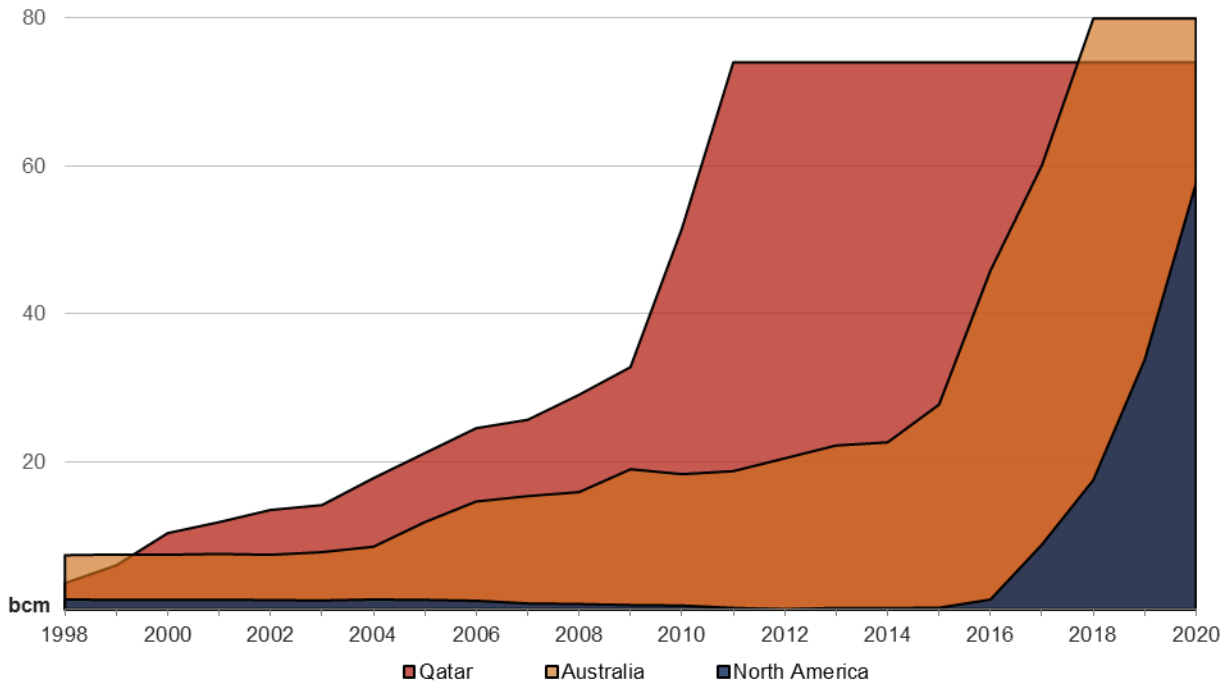
Demand growth, which has plateaued since 2012, is expected to resume once significant new supplies from Australia come online over the coming years.

Growth resumes with new supplies from Australia and the US

LNG trade will grow rapidly as new supplies enter the market from Australia and the US Gulf. It is expected that these new supplies will relieve the current tight market conditions and release pent-up demand pressures.

These expansions follow the previous rapid build-up in supply from Qatar, and together they have been characterised as the "three waves" of LNG supply (figure 4.5).

Figure 4.5 LNG export growth from Qatar, Australia and North America



Sources: BREE and Nexant.

The Australian LNG expansion consists of seven new projects currently under construction. They will increase Australian LNG nameplate capacity from 24.3 Mtpa in 2013 to 86.1 Mtpa by 2018. The new LNG production is targeted mainly at customers in Japan, Korea and China, and is under-written by long-term contracts with these customers and with portfolio players at oil-linked prices. There is also equity participation from Asian customers.

Of the US projects, Sabine Pass (18 Mtpa) is under construction, and Cameron (12 Mtpa) has achieved a final investment decision (FID) and is expected to begin production in 2019. Freeport is expected to achieve FID, and many others have received approval to export to non-FTA countries (a key hurdle to making FID). Table 4.1 shows the projects assumed to begin production by 2020.[1]

Table 4.1 North American LNG export projects

Location	Project	Status	Mtpa	Start
US Projects				
US Gulf	Sabine Pass 1 & 2	Construction	9	2016
	Sabine Pass 3 & 4	Construction	9	2017
	Sabine Pass 5	Proposed	4.5	2018
US Gulf	Freeport	Non-FTA Approved	13.2	2018
US Gulf	Lake Charles	Non-FTA Approved	15	2018
Maryland	Cove Point	Non-FTA Approved	5.2	2018
US Gulf	Cameron Phase 1	FID	6	2019
	Cameron Phase 2		6	2020
Total US			**67.9**	
Canadian Projects				
British Columbia	Douglas Island	Proposed	1.9	2018
British Columbia	Pacific Northwest	Proposed	7.4	2019
Total Canada			**9.3**	

Sources: Nexant and Company reports.

US exports will transform the market

The anticipated rapid expansion of US exports is a direct consequence of the 'shale gas revolution'. The US gas market is very large (737 bcm in 2013, compared to 639 bcm for the entire Asia Pacific), and the US has traditionally been a net importer of LNG and pipeline gas. However, the introduction of new extractive technologies has led to a rapid increase in production from the extensive shale gas reserves in the US (which are often associated with oil production). The US will soon become self-sufficient in gas, and will transition from being a net importer of LNG to a net exporter.

There are two unique aspects to this expansion of US exports:

1. A number of existing US LNG receipt and regasification terminals are no longer required for importing LNG and can be converted to LNG liquefaction and export terminals at relatively low cost (for example Sabine Pass, Cameron, Freeport and Lake Charles). This makes the US exports very competitive in Asia despite the higher transportation costs.[2]
2. The projects can access the large shale gas reserves which are readily available to the LNG projects through the existing well-developed pipeline network in the US. At the forecast

[1] The Canadian greenfields projects are more uncertain owing to their higher cost structure. Recent press reports suggest Petronas may delay the Pacific Northwest project.

[2] Transportation costs from the US Gulf and US East Coast to Asia will decline when the Panama Canal widening project is completed in 2016.

peak production of about 65 Mtpa, the LNG plants will only draw about 10 per cent of total gas production in the US. This gas will be available to the LNG plants at transparent prices traded daily at key hubs, most notably the Henry Hub located in Louisiana.

This transition has been extremely rapid, and was generally un-anticipated. It is likely to transform the global LNG market.

A new pricing paradigm

These developments in the US have led to a new business model in the LNG trade, called Henry Hub linked pricing. Under this pricing model the US producers sell LNG to customers at a price linked to the prevailing price at the Henry Hub,[3] plus a mark-up of about US$5-6 a mmbtu to cover fixed liquefaction and transportation costs. As such the producer has de-risked the gas production side of the value chain and can make a consistent return. US producers therefore bear a lower risk profile than other international suppliers where price is tied to the oil price.

At recent Henry Hub prices of US$3-5 a mmbtu the delivery price into Japan could be in the range of US$10-12 a mmbtu. This represents a significantly lower price in Asia than recent oil-linked LNG contract prices in the range of US$16-17 a mmbtu into Japan. This is attractive to potential customers, who are interested in contracts linked to Henry Hub prices, or hybrids of Henry Hub and oil price linkages. This is despite the fact that the customer takes on the production cost risk.[4]

The potential impact of this pricing model is discussed later in the section on Asian pricing.

A second consequence of the US expansion is the addition of significant new supply into the market at significantly lower prices. This will lead to pressure not just on new project negotiations from competing suppliers such as Australia, but also to significant downwards pressure on spot prices. It is also possible that a trend to lower spot prices may impact existing LNG supply contracts if these contracts have price reopener clauses.

Other supply developments

Figure 4.6 shows the current effective liquefaction capacity by country, and the anticipated growth in each region to 2020. In the case of the African projects, the effective capacity is significantly lower than the nameplate due to supply and technical difficulties. The current global installed nameplate liquefaction capacity by country is available in Appendix 4a.

After North America and Australia, the biggest expected expansion is in Africa. However, a large part of this expansion is reinstatement or replacement of existing under-performing projects. It is assumed that the Angola Soyo plant will be brought back online after the recent technical failures, and that a second train is added by 2018. It is also assumed that the Egyptian plants do not come back online due to the continuing diversion of gas production to the domestic market. However there is a prospect of gas supply to the Egyptian plants from the Israeli Leviathan field. A restart of Egyptian production would add additional LNG capacity to the global supply portfolio and create even greater competition amongst sellers.

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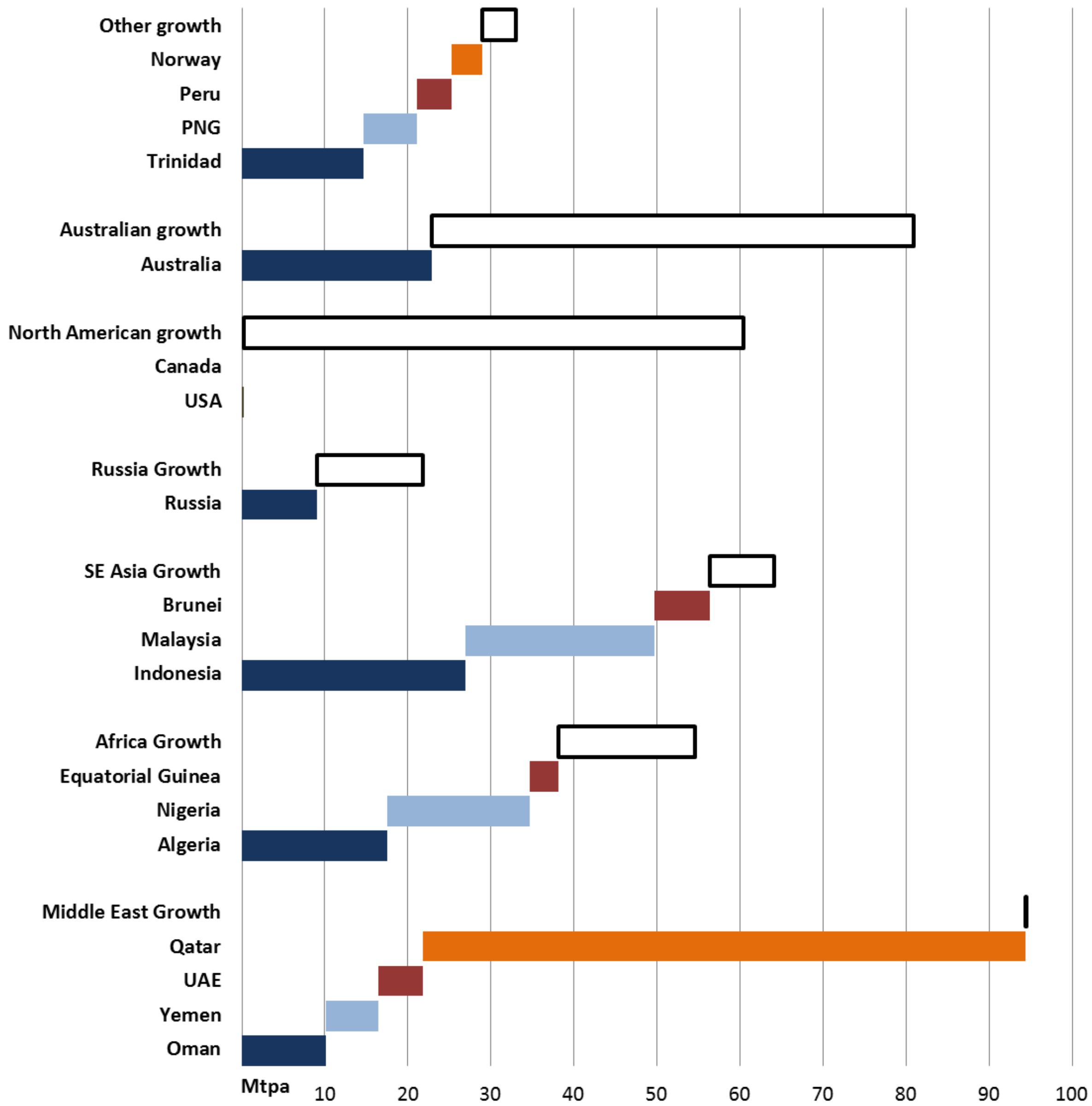
[3] BREE understands that there is a 15 per cent margin added to the Hub price.

[4] The interest in Henry Hub pricing is more likely related to the current lower prices than to de-linking from the oil price. The future for this pricing model will depend on perceptions of the direction of oil prices and US shale gas prices.

Figure 4.6 Installed LNG liquefaction capacity and growth to 2020



Sources: BREE and Nexant.

Russian LNG exports are expected to expand as the Yamal LNG project in the Arctic region is gradually commissioned from 2018. There are also prospects for additional expansions at the Vladivostock and Russian Far East projects from 2020. These projects will be assisted by the development of new gas supplies associated with the 'Power of Siberia' pipeline project, which was recently agreed between Russia and China.

There are also some anticipated expansions in Indonesia and Malaysia, including three small floating liquefied natural gas (FLNG) plants. The expansion of LNG production in east Indonesian makes up for the loss of exports from the Arun plant[5] in west Indonesia in 2014 due to the depletion of local gas reserves. A major issue for Indonesian production is the anticipated shutdown of the 22.5 Mtpa

[5] Arun is now a receipt and regasification plant supplying the Aceh region. Indonesia and Malaysia now receive LNG in the western regions and export LNG from the eastern regions. However there are potential undersea pipeline developments which could displace potential LNG trade.

Bontang plant by 2021 due to supply issues. There are, however, prospects for a deepwater gas development which could extend the life of this plant and maintain high global capacity levels.

A softer market after 2018

The rapid growth in supply is expected to lead to a softer market from 2018 which will put pressure on LNG prices. However, as is common in cyclical industries, the prospect of lower prices will support further demand growth, which at current high prices would be difficult to sustain.

Whilst an environment of lower prices is good for the development of the industry, it will make it more difficult for high cost projects to enter the market. This is particularly relevant to the prospects for new Australian projects. (See chapter 3 on LNG cost competitiveness for further discussion of this point.)

Asian LNG prices to 2020 - *growing uncertainty*

A trend to greater liquidity

The global LNG market is highly regionalised with wide divergences between contract prices in Europe and the Asia Pacific. There are also divergences between legacy contracts and new contract prices, meaning that vessels carrying LNG into the same country can be delivering LNG at significantly different prices. There is no global index that can characterise the price of LNG in the international market as there is in the case of the oil market.

This is a consequence of the dominance of bilateral long-term contracts between countries, which historically have been virtually bespoke arrangements between buyer and seller. Long-term contracting is a response to the capital intensive nature of the industry, since the delivery of LNG requires investment in liquefaction plants, regasification plants and dedicated LNG vessels in addition to the investment in gas production itself.

However, as the global trade has expanded, there has been a trend towards greater liquidity. With greater volumes being traded each year, buyers can place greater reliance on the spot market to manage the inherent volatility in supply and demand (the recent supply problems at African plants, and the surge in Japanese demand post-Fukushima demonstrate how volatile the LNG trade can be).

Another factor leading to increased liquidity is the growth of portfolio traders such as BG (UK) and Petronas (Malaysia). These parties can supply multiple customers from multiple sources in their portfolios.

Customers are also seeking greater flexibility in contractual terms and conditions of supply, in particular the removal of destination clauses in contracts which prevent the re-routing of cargoes. The goal is to free up the market and assist in balancing supply and demand. LNG re-exports is another growing trend in Europe which is expected to extend to other parts of the world.

The LNG market is facing significant uncertainty, in regard to both the direction of prices and the strength of likely demand. It is in the interests of buyers to grow the spot market, since this allows them to delay contracting for LNG until future demand and prices become clearer. This is particularly the case for Japan, which currently faces very high prices but an uncertain future demand for LNG.

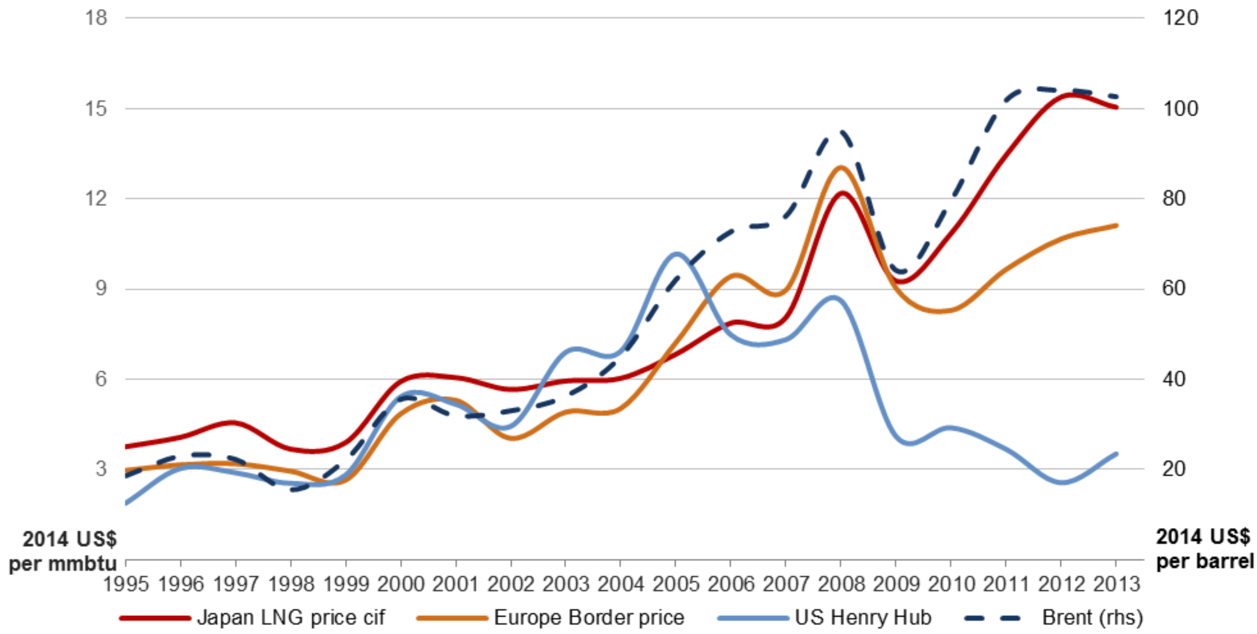
There has been considerable discussion about the possibility of the establishment of an Asian regional hub (possibly in Singapore or Shanghai) to exploit this growing liquidity. However, while a trading hub could be developed in the near future to trade spot gas, there is no certainty that the market will be deep enough to provide a basis for long-term contractual trades (as is the case with Henry Hub linked contracts).

Irrespective of the direction of the spot market, the global LNG market is becoming more inter-connected. What happens in one part of the world will affect what happens in the rest of the world. For example, if European LNG demand grows more rapidly than is expected, then Europe will absorb more capacity from Qatar and the US Gulf, which will open up more opportunities for countries like Australia that export to the Asian region.

Regional gas prices have diverged

Figure 4.7 shows the historical trends in gas prices in Europe (pipeline gas delivered to the border), the US (the Henry Hub traded price), and in Japan (delivered LNG price), all compared to the price of Brent Crude oil.[6]

Figure 4.7 Global natural gas and oil prices



Source: World Bank.

Natural gas prices tracked the oil price in all regions until 2005, when expanded US shale gas production (in association with shale oil production) led to a substantial drop in US gas prices and de-linkage of gas and oil prices. European prices of gas delivered by pipeline also tracked oil prices until 2008 but are now significantly lower at $11-12 a gigajoule. This is, in part, a competitive response to the slowing of gas demand in Europe.

Japanese LNG imports have continued to track oil prices, resulting in a significant divergence in prices between Asia and the rest of the world. This is contributing to a major trade deficit in Japan

[6] The oil price on the RHS of the graphic in US$ a barrel is correlated to the LNG price in US$ a mmbtu at a ratio of 15 a cent, which equates the prices per unit of heat derived from the combustion of oil or LNG (i.e. oil at $100 a barrel is equivalent to $15 a gigajoule of combusted LNG).

(although similar issues apply in all Asian LNG importing countries), and has stimulated the recent interest by Asian consumers in LNG exports from the US at prices linked to the Henry Hub index rather than to oil prices.

Asian LNG contracts

The principal pricing model for contracts in the Asia Pacific is oil-linked pricing based around the JCC (Japanese Customs-cleared Crude or Japan Crude Cocktail) price, a close proxy to the Brent crude price.

LNG is sold at a price which is a proportion of the JCC price, where the ratio is a measure of the relative value of oil and natural gas. For example, if oil is priced in US$ a barrel, and LNG is priced in US$ per mmbtu,[7] then a ratio of 15 per cent between the two prices corresponds to an equal price for the heat energy produced by the combustion of LNG or oil. A ratio lower than 15 per cent means that the LNG is priced at a discount to the corresponding oil price, reflecting the different utility of oil and natural gas.

The contract price also includes a constant term to capture the cost of transportation. Contracts can also include negotiated upper and lower caps to provide some stability in the returns to producers and protection for customers.

As an example, if the JCC price is US$100 a barrel, and the constant term is US$1.60 a mmbtu, then at a contract ratio (or slope) of 14 per cent, the oil-linked contract price is US$15.6 a mmbtu:

$15.60 a mmbtu = 0.14 * $100 a barrel + $1.60 a mmbtu

Oil-linked pricing has the advantage that the oil price index is a globally traded reference point that cannot easily be manipulated by any one seller nation. In addition, oil-linkage ensures that a buyer is paying close to the next best alternative fuel, and therefore will not be paying more than the competitive fuel price.

However as the oil price has escalated to very high levels as shown in figure 4.7, the main issue for buyers in Asia has become the absolute level of the LNG price, and this is driving the search for more competitive alternatives for their energy supplies.

Asian LNG prices trend downwards

Figure 4.8 shows a projection of Japanese spot and contract prices to 2020, based on a range of possible outcomes for future oil prices. The contract price scenario is the price for an oil-linked contract for Australian LNG delivered into Japan. It is derived from the forecast of the JCC price (based on Brent crude) which is assumed to be US$85 a barrel in 2015 and have a range of US$80 to US$95 a barrel by 2020. The slope factor is assumed to be 14 per cent, which is indicative of recent contracts for Australian LNG delivered into Japan.[8]

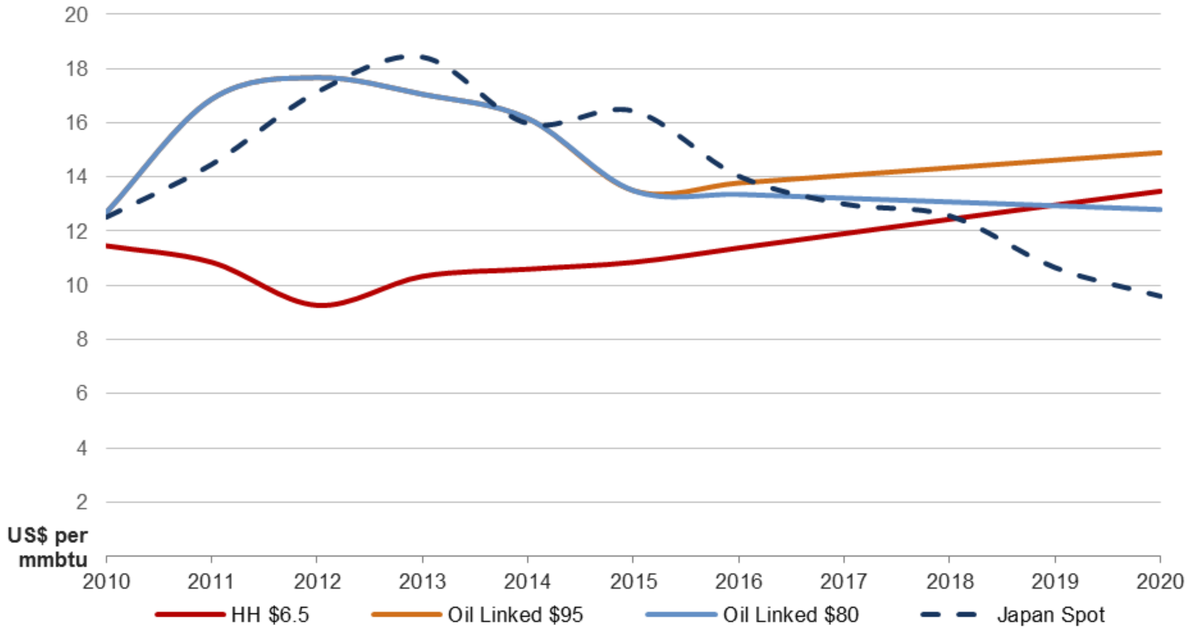
[7] One mmbtu (million British Thermal Units) is equal to 1.055 gigajoules.

[8] BREE does not know if these prices exceed or fall below the upper and lower contract bounds.

The Henry Hub linked price is the price for US Gulf sourced LNG delivered to Japan, and based upon an assumption of a Henry Hub price rising from US$4 a mmbtu to US$6.5 a mmbtu.[9] It is assumed there is a mark-up of US$6 a mmbtu to account for fixed costs of liquefaction and transportation.

The Japan spot price scenario has been generated by modelling using the Nexant WGM. The collapse of the spot price after 2018 is a consequence of the excess of supply over demand which is contained in the forecast shown in figure 4.4. Whilst this result is sensitive to the details of the supply and demand scenario, it does suggest the likely direction of spot prices over the period.

Figure 4.8 Japanese price outlook



Sources: BREE and Nexant.

The direction of spot prices after 2020 will be strongly dependent on the rate of growth of LNG demand in an environment where there is plentiful supply. Based on the forecast described later in the long-term outlook, the spot price is not expected to return to previous highs, and it is likely to stay under US$12 a mmbtu until such time as demand growth picks up.

The conclusions from these observations are:

1. Competition in the LNG market will intensify in the face of strong growth in LNG supply, pipeline construction and increased indigenous gas production.
2. Asian contract prices are likely to fall, unless oil prices return to previous highs. However prices are unlikely to fall to the levels of previous decades, which means that growth in gas demand will be constrained by competitive pressures for the foreseeable future.
3. Spot prices are likely to fall from 2018, in response to the growth in LNG supply. This could have a number of medium term consequences, including:
    a. pressure to delay LNG projects

[9] Whilst US$6.5 a mmbtu is at the high end of expectations, we have taken into account the potential upward pressure on Henry Hub prices in the US as production increases to accommodate the growth of gas exports. Additionally, there is the possibility that shale gas costs could rise if associated liquids production falls.

b. reductions in production to take-or-pay levels (estimated to be around 85 per cent of full contract volumes), and diversion of cargoes to the spot market.

Australian LNG – *can Australia compete?*

Australian LNG production is expanding rapidly, but Australia has sufficient gas resources to further increase production significantly in the future. Australia's extensive undeveloped gas resources are discussed in chapter 1. They include the large CSG reserves held by Arrow in the Bowen and Surat basins in Queensland, and the extensive offshore conventional gas reserves of the Carnarvon, Browse and Bonaparte basins off Western Australia and the Northern Territory.[10]

However, a number of the projects currently under construction have experienced delays and cost escalation. For example the cost of the Gorgon project has escalated 45 per cent from initial estimates to US$54 billion (US$3462 a tonne per annum (tpa)), compared to the cost for the recently completed PNG LNG project at approximately US$2750 a tpa.

Table 4.2 shows the estimated costs for the Australian projects currently under construction.[11]

Table 4.2 Unit capital costs for Australian LNG projects

	Capacity (Mtpa)	US$ billion	US$/tonne pa
Prelude	3.6	12.6	3500
Wheatstone	8.9	29	3258
Gorgon	15.6	54	3462
Ichthys	8.4	33	3929
Average	**36.5**	**128.6**	**3523**
QCLNG	8.5	19.8	2329
GLNG	7.8	18	2308
APLNG	9	24.7	2744
Average	**25.3**	**62.5**	**2470**
Total	**61.8**	**191.1**	**3092**

Sources: BREE and Company reports.

Care must be taken in interpreting these costs. Firstly the Queensland CSG projects require on-going drilling and field development in order to maintain production. This could add as much as 50 per cent to the capital costs of the Queensland projects, depending on the cost of new well developments which would bring their unit costs up to levels comparable with the offshore Western Australian projects.

Secondly the unit project costs are not always directly comparable because of the variety of outputs from each project. For example, the Gorgon and Wheatstone projects will also produce gas for the domestic market, and some projects, notably the Ichthys and Prelude projects, produce significant additional liquids outputs which offsets some of the development costs.

Nevertheless, McKinsey and Company recently reported a competition analysis which concluded that Australian costs had escalated to such an extent that they were now 30 per cent higher than competitors from the US, Russia and East Africa.[12] There are many factors which have led to these

[10] Plus prospective reserves of unconventional gas in the Cooper Basin and Northern Territory.

[11] BREE, *Resources and Energy Major Projects*, April 2014.

[12] McKinsey and Company (2013). *Extending the LNG boom: Improving Australian LNG productivity and competitiveness*.

relatively high costs, but irrespective of the reasons, Australian projects will need to improve productivity in order to compete in the next wave of capacity expansions.

There are a number of specific projects currently under consideration to expand Australian LNG production, as shown in Table 4.3 (none has yet achieved FID). These projects can be classified into two categories. Firstly there are FLNG projects, exploiting the same new technology being implemented in the Prelude project in the Browse Basin. As of 2014, there are no operating FLNG plants in the world, so it is difficult to assess whether this technology will be a viable and competitive option for other projects.

Secondly, there are brownfields projects which exploit existing facilities and infrastructure. For example the Darwin or Gorgon liquefaction facilities can be expanded by making use of the existing pipelines, storages, jetties and other infrastructure at a lower cost than constructing a greenfields project.

Table 4.3 Proposed Australian LNG projects

Project	Basin	Capacity Mtpa
Western market		
Scarborough FLNG	Carnarvon	6
Gorgon 4th Train	Carnarvon	5.2
Browse FLNG	Browse	n/a
Northern market		
Bonaparte	Bonaparte	n/a
Sunrise	Timor Sea	4
Cash Maple (FLNG or conv.)	Timor Sea	2
Eastern market		
Arrow (CSG)	Bowen-Surat	8

Sources: BREE and Company reports.

The prospects for the projects listed above will depend on two factors:

- the demand for LNG, principally in the Asian market, over the life of the proposed project
- the competitiveness of these projects compared to alternative international projects

The demand outlook beyond 2020 is discussed in the next section. The long term scenario is subject to considerable uncertainty, since it requires not just an analysis of the competitiveness of gas against alternative energy sources (coal, nuclear, renewables), but also an assessment of the competitiveness of LNG imports against increased indigenous production and pipeline imports. The analysis and modelling done for the period 2020 to 2030 suggests that LNG trade will continue to grow, but at a reduced rate. This is due to continuing growth in pipeline infrastructure, and to growth in indigenous production, in particular shale gas.

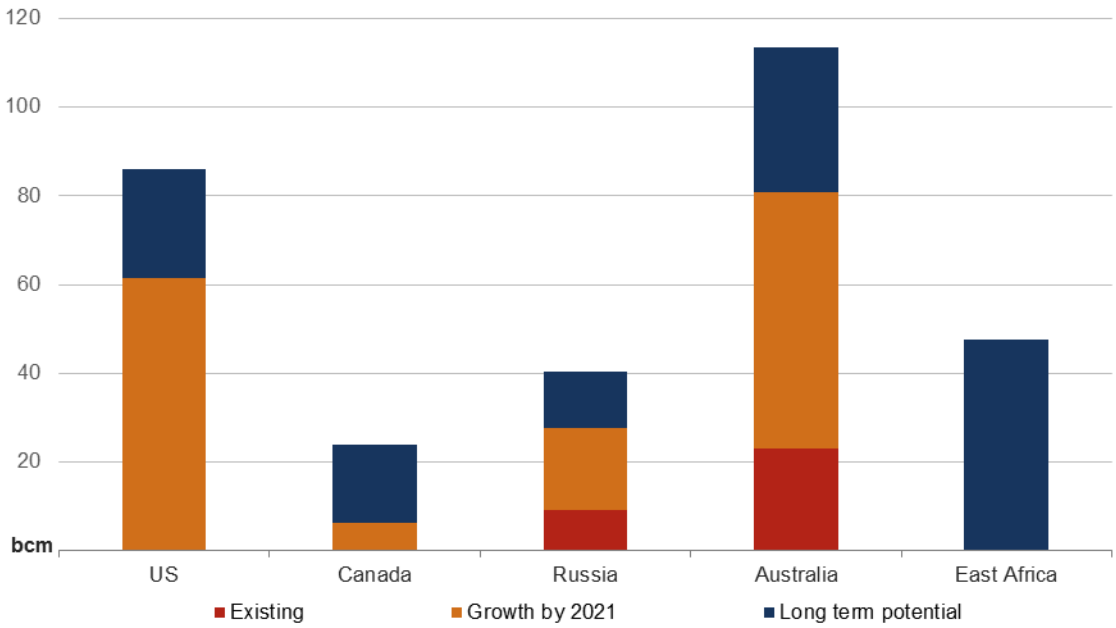
Based on this analysis, the market post 2020 is expected to be characterised by moderating and uncertain demand. This will increase the pressure on new LNG production in Australia in competition with alternative LNG projects in the international market.

Figure 4.9 shows the capacity available from potential LNG developments around the globe. These estimates are based on projections of planned and prospective projects that are likely to be competitive - many other projects have been mooted.

The potential Russian projects include the Vladivostok and/or Russia Far East projects. The prospects for these projects have improved with the agreement to construct the 'Power of Siberia' pipeline which will support the development of new gas production in the Russian Far East.

The potential East African projects consist of offshore developments in Mozambique and Tanzania. These are likely to be at least 10 years off due to lack of infrastructure and a still developing regulatory framework. However the recently discovered gas resources are very large and potentially very competitive.

Figure 4.9 Prospective LNG capacity post-2020



Sources: BREE and Nexant.

In the US the total LNG export capacity from existing proposals under consideration exceeds 200 Mtpa. However, given global supply competition it is unlikely all these projects will go ahead. LNG exports are likely to put pressure on domestic prices, and as a guide a maximum export capacity of approximately 15 per cent of US demand is assumed.

The market post-2020 is likely to be highly competitive, and in such an environment cost will be the main determinant of success. However there are a number of factors that could improve the outlook for Australian production:

- The economics of FLNG are likely to improve as the technology matures. This would favour the exploitation of the large conventional gas reserves on the continental shelf off Western Australia and the Northern Territory (however it might take some time for this technology to prove itself and mature)
- A number of Australian projects will be brownfields developments. In addition, Australian projects could benefit from an existing experienced workforce. This would favour Australia in comparison with greenfields developments in Canada and East Africa
- Australia has the advantage of proximity to the Asian markets
- A key factor in the economics of gas production is the extent of associated liquids. For example, the Ichthys project in the Browse basin benefits from extensive associated liquids production. Australian projects with associated liquids will have a significant competitive

advantage over other projects (although this does not apply to the Queensland CSG fields which produce 'dry' gas)

- Australia is politically stable and has a history as a reliable and consistent supplier. This point is brought into sharp relief when compared to the technical and supply problems that have plagued projects overseas, and cases where supply has been withdrawn from LNG production in order to serve the domestic market (as in Egypt)

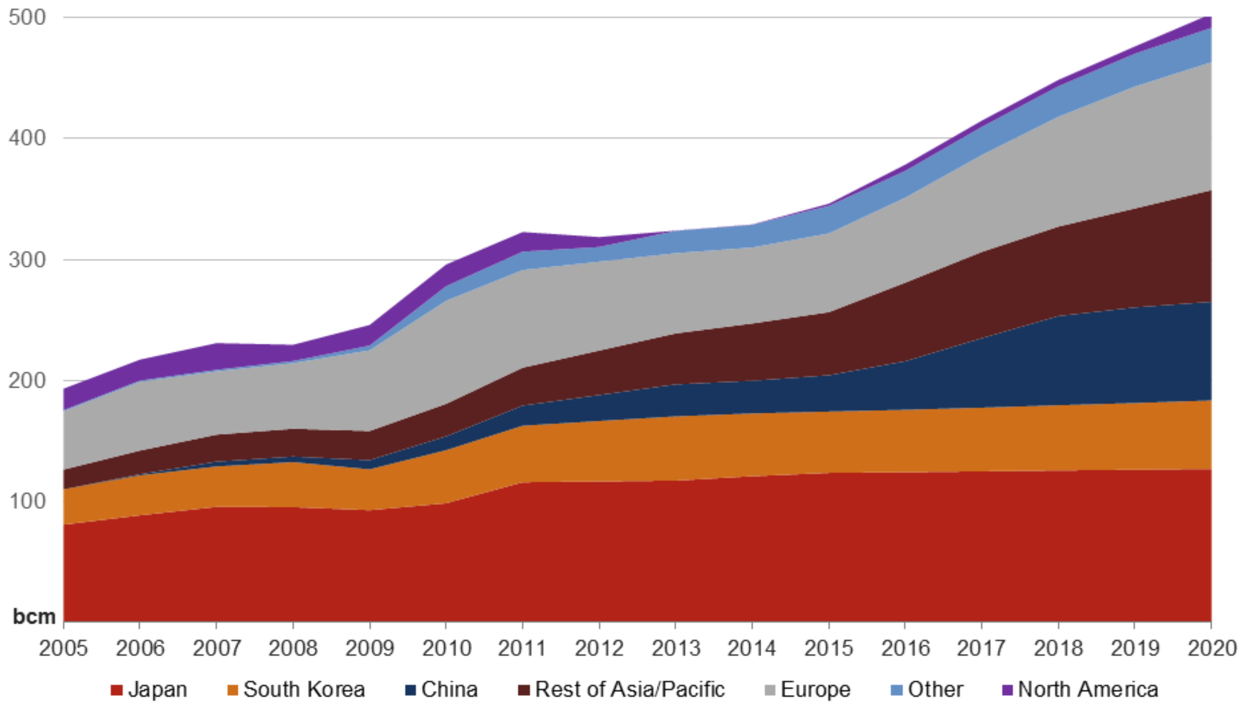
Other countries also have access to brownfields development, and/or could exploit FLNG technology. Therefore it is likely that the competitiveness of Australian prospects can only be assessed on a case-by-case basis, but there is a strong incentive for all project proponents to keep costs under control.

In light of all these considerations, our current assessment is that the LNG market post-2020 will be a buyer's market, and that new LNG contract prices are likely to moderate in light of the potential competition from alternative LNG and pipeline suppliers. The price of Russian gas into China estimated at US$12-14 a mmbtu is likely to be a guide to the competitive benchmark that will apply after 2020.

LNG demand to 2020 – *the demand drivers shift to China and the rest of Asia*

Global LNG imports are expected to accelerate rapidly after 2015 as new supply from Australia enters the market. Asia grows strongly, although growth in Japan and South Korea moderates. Nevertheless Japan is still expected to remain the largest single importer of LNG.

Figure 4.10 Global LNG imports by country



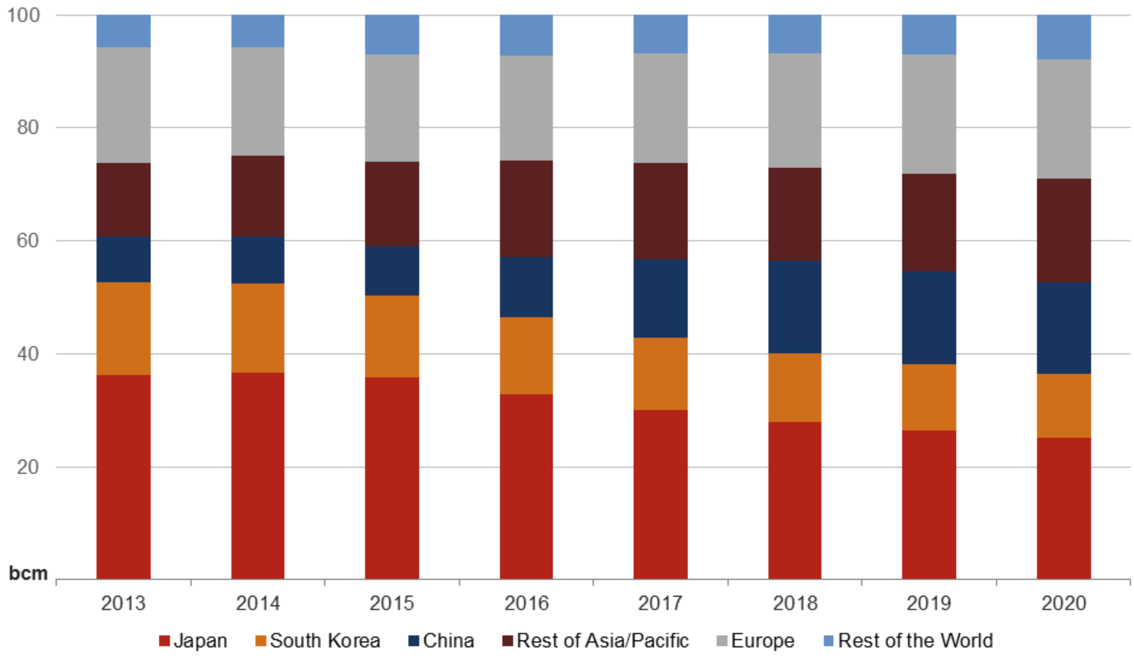
Sources: BREE and Nexant.

In the rest of the world, the main importer is Europe, and some growth is also anticipated in Latin America. The forecast for Europe shows a significant 60 per cent growth to 2020 albeit from a depressed base. The drivers of LNG demand in Europe are discussed later in the long-term outlook.

Growth momentum shifts to China and the rest of Asia

As figure 4.11 shows, the Asia Pacific region maintains approximately 70 per cent of the global LNG trade which has prevailed since 1980. However the engine of growth is switching from Japan and South Korea to China and other Asia Pacific nations.

Figure 4.11 Global share of LNG imports

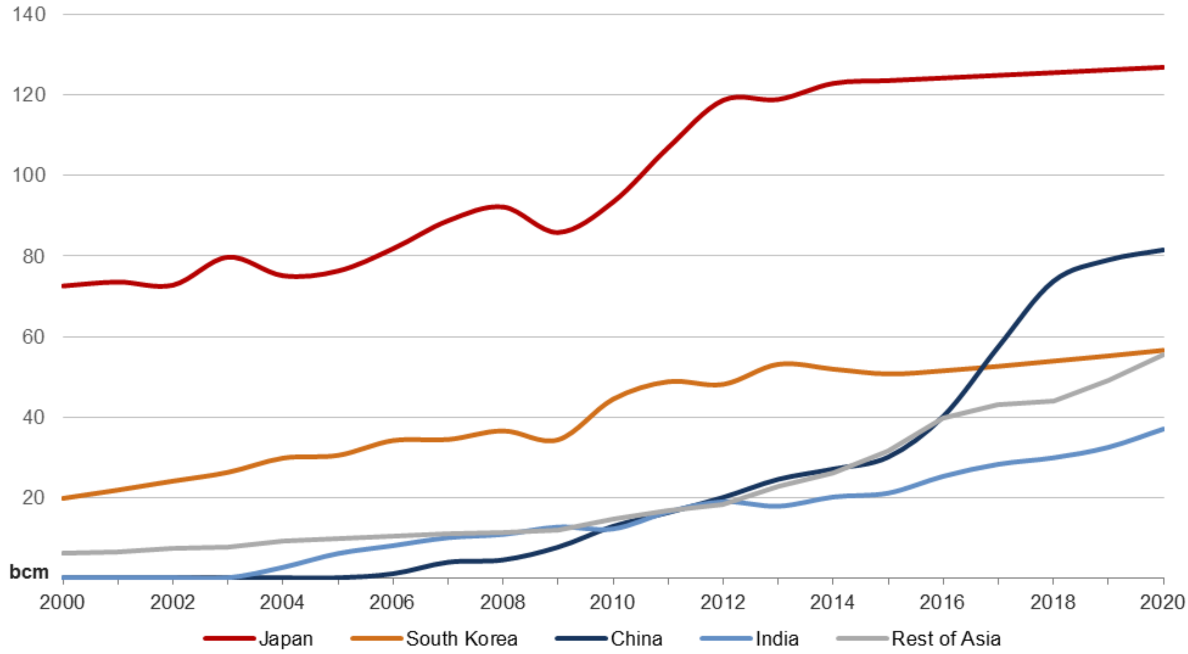


Sources: BREE and Nexant.

Drivers of Asian demand

Growth in Japan and South Korea is expected to moderate. The rapid growth in China will see it overtake South Korea as the world's second largest importer of LNG by 2017. However growth in India and the rest of Asia (mainly Chinese Taipei) is also significant over the forecast period, as shown in figure 4.12.

Figure 4.12 Asian LNG imports outlook



Sources: BREE and Nexant.

Japan

Japan has very little local gas production and it is currently not supplied by pipelines, hence almost all natural gas has to be imported as LNG. Japanese LNG demand has been growing at a consistent rate since 1969 as gas has penetrated the reticulated and power generation markets. However, after the March 2011 Fukushima disaster, oil and gas demand increased significantly as the entire fleet of 54 nuclear reactors was gradually shut down. Combined with the recent increases in oil and LNG prices, and the depreciation of the yen, this has placed considerable pressure on the Japanese economy and balance of trade. As a result, the Abe government has stated an intention to restart those reactors which are deemed safe to do so, but there is public resistance. It is understood that the first 16-20 reactor restarts would displace oil imports rather than LNG.

There is significant uncertainty in the LNG forecast for Japan. It is not clear how many reactors will be restarted, nor the penetration of new coal fired plants (expected after 2020). Although the price of oil and LNG is expected to decline over the next 5 years, they will still be higher than historical levels which will contribute to greater renewables penetration and conservation measures. Hence even if no nuclear restarts occur, the previous growth rate is not expected to be maintained.

There is considerable downside risk to this forecast owing to the potential for more nuclear restarts to occur and for concerted action by the Japanese government to reduce its balance of trade deficit.

South Korea

South Korea is the second largest importer of LNG in the world. Like Japan, it has very little indigenous production, and is not supplied by pipelines. Demand has been growing steadily, with current consumption split equally between power generation and reticulated distribution. Korea Gas (KOGAS) is the single largest buyer of LNG in the world.

Gas has a fairly high penetration of the energy market with 17 per cent of total primary energy demand in 2011, compared to nuclear power with 13 per cent. The prospects for gas demand depend strongly on the South Korean government's plans for the expansion of nuclear power, which until recently was intended to increase from 26 per cent of the electricity market to 41 per cent by 2035. However, there have been safety concerns at some reactors which prompted temporary shutdowns. This has in turn led to a short-term rise in LNG imports for power generation. Based on the latest energy policy announcements, the expansion of the nuclear program is likely to proceed at a slower pace with a reduced target of 29 per cent of the generation mix.

Demand growth is therefore expected to moderate as the energy mix continues to shift to both nuclear and renewables, with some prospects for coal in the longer term. A key factor in this scenario will be the price of imported LNG, which at its current high levels is not likely to support sustained growth.

China

The penetration of natural gas in China is growing rapidly but from a low base of only 5 per cent of total primary energy demand in 2012. Growth is occurring in the reticulated, industrial and transport markets, and in the power generation market where it is seen as a cleaner alternative to coal-fired generation.

The pace of change is so great that it is difficult to settle on a consistent forecast of demand, and there is significant movement in published forecasts. Total gas demand is expected to grow from 165 bcm in 2013 to 340 bcm by 2020, a growth rate of 10.8 per cent a year. However, there are many factors which bear on this forecast - most notably gas prices - and as legacy LNG suppliers are phased out and new more expensive LNG suppliers enter the mix, it is conceivable that demand growth will be moderated. A major factor driving the high growth rate in gas consumption is the desire to clean up the air pollution caused by burning coal domestically and in power stations. However there are recent indications that this goal is being achieved by installing pollution control measures on existing coal-fired power plants, rather than converting to gas-fired plants, and if this trend continues then the rate of demand growth could moderate.

In addition to the uncertainty about the total gas demand level, there is the added complication of competition between LNG and pipeline imports (as shown in figure 4.13). China already imports pipeline gas from Myanmar and Central Asia, and pipeline imports of 27.4 bcm in 2013 exceeded LNG imports of 24.5 bcm. The Myanmar-China pipeline has a capacity of 12 bcm a year, and the Central Asia-China pipeline (Lines A and B) has a capacity of 30 bcm a year. This pipeline accesses the super-giant Galkynysh field in Turkmenistan, amongst others. With the completion of the 1830 km Line C in 2015, capacity will increase to 55 bcm a year, and when Line D is completed (thought to be around 2018), capacity from Central Asia will reach 80 bcm a year (more than twice the capacity of the LNG plants at Gladstone). These pipelines alone could supply 27 per cent of the forecast gas demand in China by 2020. In addition, China has recently signed a contract for Russian pipeline supply through the 'Power of Siberia' pipeline (the red pipeline in figure 4.13) which is expected to supply 38 bcm a year as it is constructed in stages over the period 2018-2022.

Figure 14.3 Proposed Russia-China pipeline projects

Source: RT.[13]

There are prospects for further expansion of this Russian pipeline, and for a new route via the Altai Pass into North West China (the pipeline shown in blue). It is estimated that the Russian gas will be delivered in China at about US$12-$14 per mmbtu, which is comparable with the anticipated cost of LNG imports from the US, and very competitive with new contracted Australian LNG into China.[14]

Taking these issue into account – the increase in pipeline supply, the growth of indigenous production, potential delays in the construction of infrastructure, and the introduction of cleaner coal technologies, it is possible that the Chinese market may not be able to absorb all of the forecast LNG imports over the medium term. Compounding this problem is the seasonality of the North Chinese market and the lack of sufficient storage to balance supply and demand. In such circumstances it is possible that LNG supply to China might show some volatility and that contracted LNG supplies may on occasion be reduced to take-or-pay levels, or diverted to the spot market.

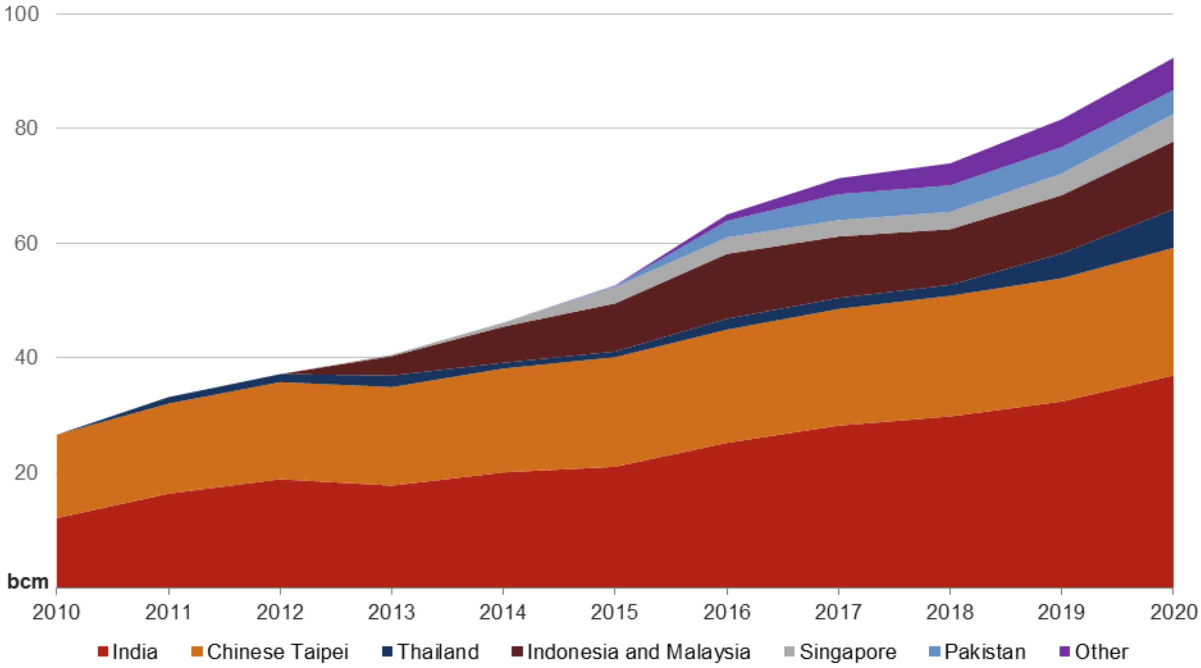
Rest of Asia

Moderate growth in both India and Chinese Taipei is anticipated to continue, but as more Asia Pacific nations construct LNG import and regasification terminals the cumulative demand grows rapidly, as shown in figure 4.14.

[13] Russia Today, available at: http://rt.com/business/203087-putin-china-gas-deal/.

[14] However, Australian LNG will have an advantage in supply to southern coastal China due to the additional cost of pipeline transportation within China from the north and north west.

Figure 4.14 LNG imports in the rest of Asia



Sources: BREE and Nexant.

With the exception of Chinese Taipei and the Philippines, these countries have access to indigenous production and/or pipeline supplies. Therefore, as is the case in China, the longer term prospects for LNG imports will depend on the competitive position of LNG imports vis-à-vis expanded local production or production from neighbouring countries delivered through pipelines.

A factor favouring continued growth in LNG imports in these countries is the growth in domestic demand as electrification and industrialisation creates greater demand for clean burning natural gas. However, LNG is at the high end of the cost curve, so there are strong national incentives to develop local production and to expand the pipeline networks throughout South East Asia and the sub-continent.

The forecast for LNG imports into Malaysia and Indonesia reflects this tension. As gas fields in the west are depleted (such as the fields supplying the Arun plant in Sumatra which was recently converted to an import terminal), the large resources in and around the islands from Borneo to West Papua have been developed to supply both the domestic and export markets. The forecast shows an increase in imports from these regions to the centres of demand in the western provinces of Malaysia and Indonesia and elsewhere. However, in these regions the growth of pipeline networks and local production will be a major constraint of the continued growth of LNG imports.

The longer term outlook – *uncertain demand but plentiful supply*

Gas demand outlook to 2030

Gas demand is expected to grow rapidly over the next 15 years, but earlier predictions of a ’golden age of gas’ have been moderated as the price of gas has risen at a faster rate than alternative sources of energy. Gas is still valued for its clean burning properties and moderate greenhouse gas emissions, but economic factors are becoming more relevant.

Gas will need to compete on price against the alternatives – coal, oil, nuclear and renewables – for its share of total primary energy demand. This overall demand in turn depends on many factors – population growth, economic development, and the efficiency with which energy is used. To add to these uncertainties, forecasters must also consider the range of possible responses to greenhouse gas reduction, and public concerns with pollution and nuclear safety.

Wood Mackenzie recently reviewed a range of alternative long term forecasts of gas demand (Wood Mackenzie, IEA New Policies, BP and ExxonMobil).[15] They found a wide divergence of views on the rate of growth of total energy demand, mainly due to different views on the rate at which energy intensity declines between OECD and developing countries. However, these forecasts differed more on the relative growth rates of coal and renewables in the energy mix, and tended to be more consistent in their assessment of the demand for gas. Nevertheless, forecasts over long time periods will always be subject to high degrees of uncertainty and be subject to review.

The following forecasts are based on the 2013 IEA New Policies forecasts, adjusted for more recent thinking in the Medium Term Gas Report 2014 and in-house analysis.

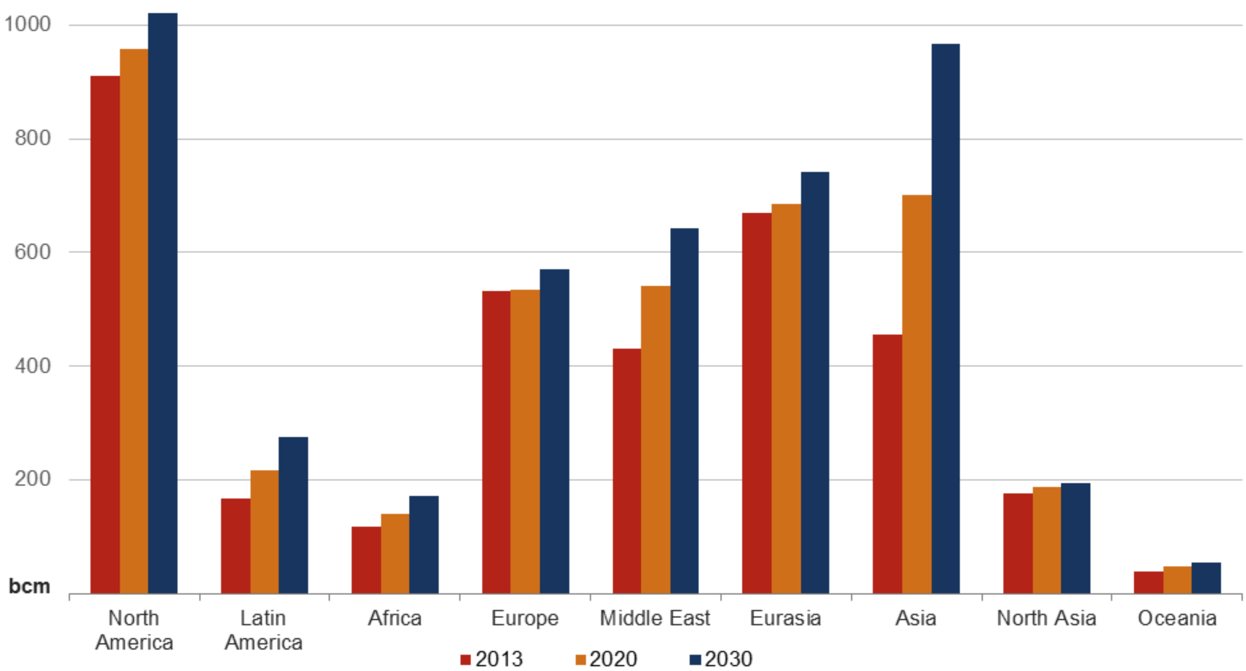
Table 4.4 Global gas demand to 2030

	2013	2020	2030
Demand (bcm)	3500	4010	4635
Annual growth rate		2.0 per cent	1.5 per cent

Sources: BREE and Nexant.

The breakdown of this total gas demand forecast by region is shown in figure 4.15.

Figure 4.15 Gas demand by region to 2030



Sources: BREE; IEA and Nexant.

[15] Wood Mackenzie Energy View to 2030: *A comparison to IEA, BP, ExxonMobil, EIA and OPEC*, July 2014

The main features of this projection are: [16]

- US demand is growing rapidly, but production particularly of shale gas is growing at a more rapid rate. The US is expected to transition from being a net importer to a net exporter over the next five years
- European demand is stagnant as energy demand slows and renewables (and to some extent also coal) increase their share of the market
- Middle East demand grows rapidly, but this is stimulated by a rapid expansion in domestic gas supply, and it is not anticipated that gas exports outside the region will increase significantly – a key factor will be impacts of geopolitical developments in the region
- Asian demand shows the most rapid growth as industrialisation and electrification continue in developing countries
- Growth in the mature north Asia economies of Japan and South Korea is slower, because the economies are mature and there is likely to be further growth in nuclear, renewables and coal

Global LNG demand outlook to 2030

The main factors influencing LNG trade over the next 15 years will be:

- the growth of shale gas production in the US, which will make the US a net exporter of LNG
- the growth of shale gas production in China, which will reduce the growth rate of LNG imports into China
- competition between LNG and pipeline supplies into Europe, which has the potential to limit (or increase) European LNG imports

Forecasting the LNG market is particularly difficult since LNG imports are the balancing item when demand cannot be supplied by more economical local production and pipeline imports. LNG imports are:

- at the high end of the cost curve
- traded mainly through long term bilateral contracts with long lead times between initial proposal and delivery
- subject to geopolitical influences

The long term forecast of LNG imports shown below has been calculated using the Nexant World Gas Model, and the gas demand forecasts described in the previous section. This model calculates the mix of indigenous production, pipeline imports and LNG imports that leads to the least cost of supply to each country. Existing LNG and pipeline contracts are taken into account.

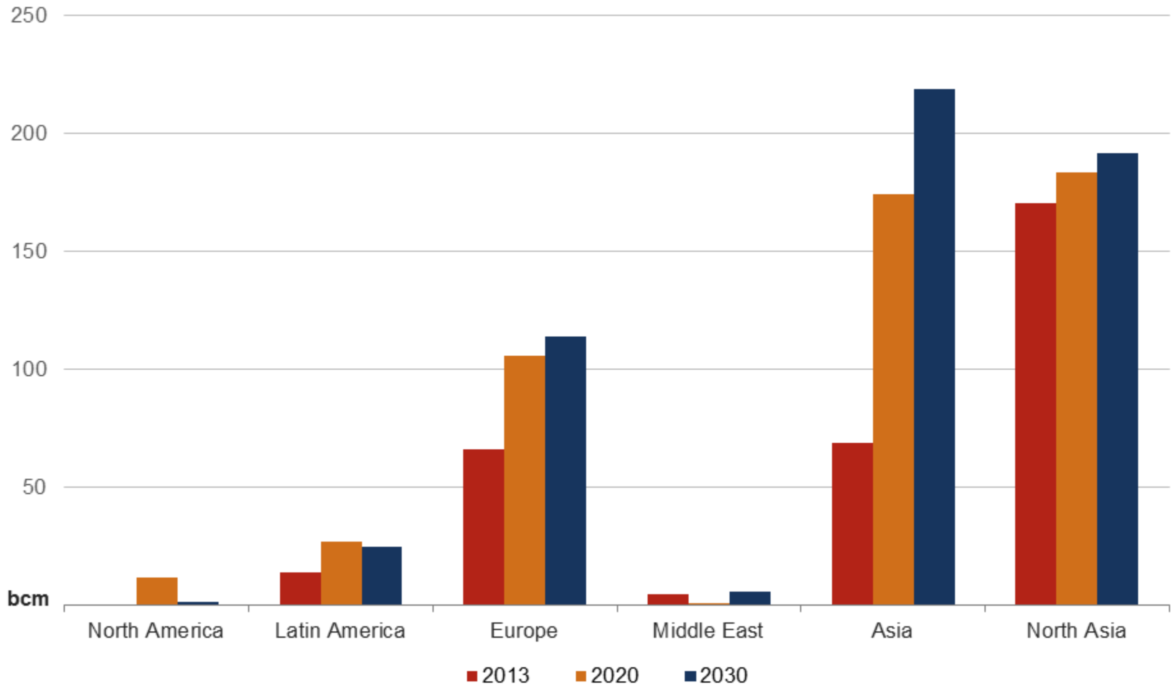
LNG imports are forecast to grow from 324 bcm in 2013 to 503 bcm by 2020, a growth rate of 6.5 per cent a year. This reflects, in part, the release of pent-up demand as new Australian and US supply comes online. However, LNG imports growth is expected to slow after 2020 and is projected

[16] These regional groupings follow the IGU definitions, with the exception that Asia and the Asia Pacific are grouped together under Asia, and North Asia (Japan and South Korea) and Oceania are treated separately. Eurasia is the countries of the Former Soviet Union.

to reach 557 bcm in 2030. The slower growth to 2030 is due to higher indigenous production in most regions (especially of shale and unconventional gas), and increased imports by pipeline.

The long term forecast relies on the balancing of many options and is based on the assumed costs of field production, pipeline tariffs and LNG costs, often for projects which are still only proposals. Therefore the results should be considered as a guide to the main drivers of LNG demand in the future. In reality market participants will adapt to conditions, seek economies, and delay or bring forward projects. As stated at the beginning of this chapter, the LNG market is volatile, and long term forecasts should be treated as indicative only.

Figure 4.16 Regional demand for LNG to 2030



Sources: BREE and Nexant.

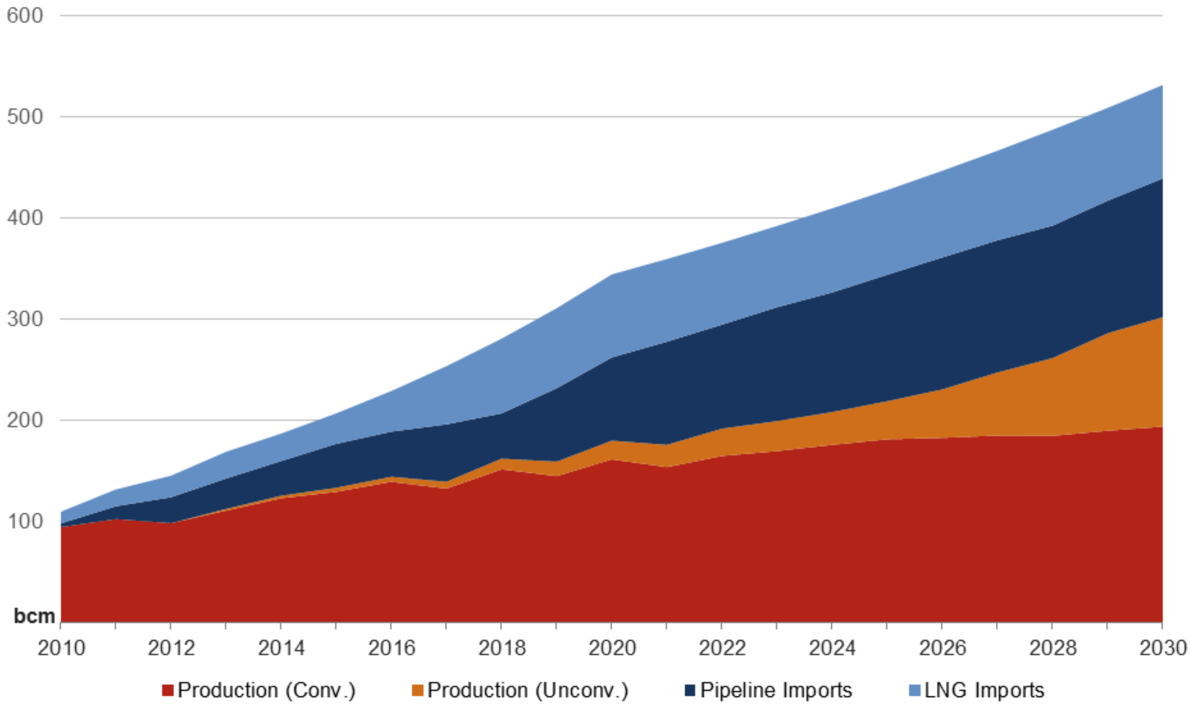
Although the level of imports is indicative, Asia is forecast to remain the engine of growth in the long term, although growth slows as shale gas production and pipeline imports increase in China. Imports into Europe also slow as overall demand remains sluggish. Latin American imports fall despite the increase in gas demand, as local production increases at a faster rate, as shown in figure 4.16.

The following two sections describe this projection in more detail, with reference to developments in China and Europe.

Chinese supply and demand balance to 2030

Figure 4.17 shows the forecast of local Chinese production, pipeline imports and LNG imports. The local production is divided into conventional and unconventional production to show the increasing exploitation of shale gas (and to a lesser extent CSG and coal-to-gas production).

Figure 4.17 Chinese supply and demand balance to 2030



Sources: BREE and Nexant.

The main factors limiting the growth of LNG imports are increases in pipeline imports from Russia and Central Asia, and increases in shale gas production.

The forecast of shale gas production is critical to this outlook but it is still a developing industry and the costs and technical feasibility of expanded production are uncertain. The Chinese government has set high targets for shale gas production by 2020, and a number of international companies such as Shell are active in exploration and development. The short term targets are unlikely to be met, but the long term potential is significant. It has been suggested that Chinese shale gas resources are deep, lack sufficient water resources and are not associated with liquids as is the case with the US shale gas fields. However, Chinese shale gas developments do not have to match the US$4 a mmbtu cost of US shale, but rather the competing alternatives of pipeline and LNG imports which are unlikely to fall below US$10-$12 a mmbtu.

The forecast of pipeline imports is based on continued growth of Central Asian and Russian supplies. The gas resources in these countries are extremely large and in the case of Russia there is an incentive to 'pivot east' as Europe seeks to diversify its gas supply.

The latest IEA forecast projects a slightly lower total gas demand in the medium to long term than shown above.[17] However this would not significantly change the conclusions of the analysis.

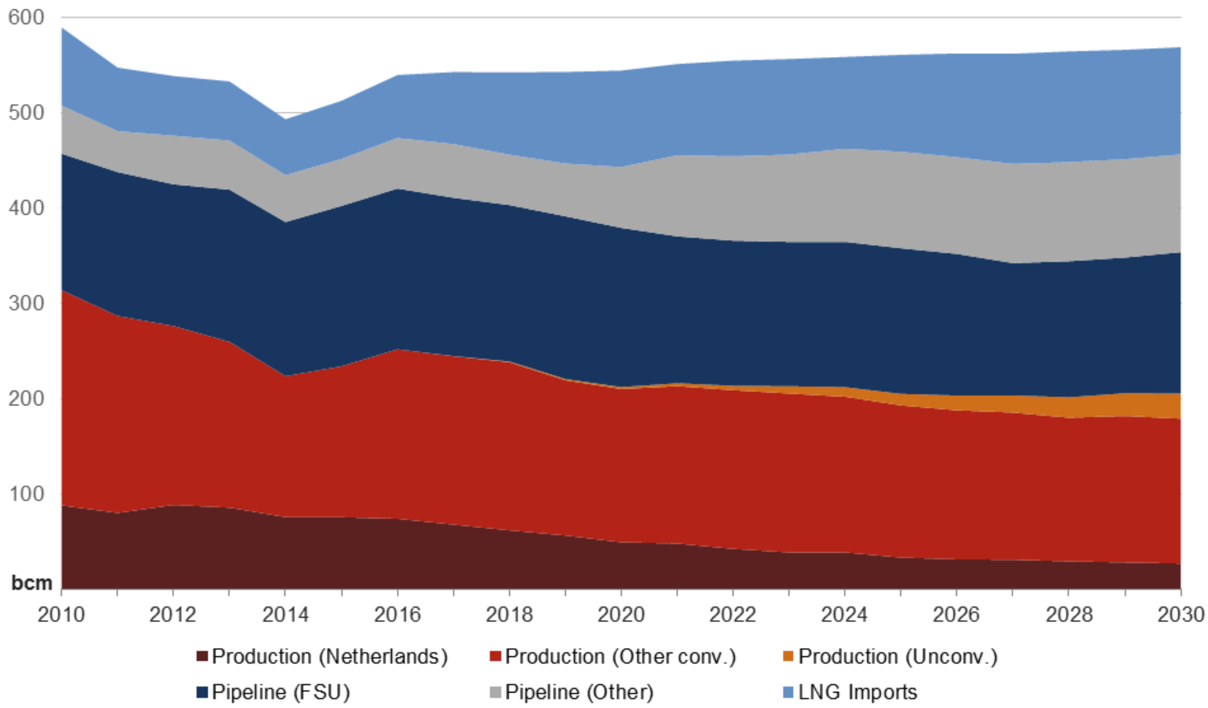
In summary, the pace of change in China is extremely fast, and there is significant movement in published forecasts. There are many other factors than those mentioned above which could increase or decrease LNG imports, such as response to climate change and efforts to reduce air pollution. Whatever the outcome, LNG imports must be price-competitive with a wide range of alternatives.

[17] IEA *World Energy Outlook 2014*, November 2014

European supply and demand balance to 2030

European gas demand is expected to be stagnant over the whole period to 2030. However, there is growing demand for imports as local production falls. As figure 4.18 shows, this is caused by the decline in production from the Netherlands, in particular from the Groningen field which has been associated with increased earthquake activity. However, production from Norway is expected to continue at current rates, and there is a small contribution late in the period from shale gas development.

Figure 4.18 European supply and demand balance



Sources: BREE and Nexant.

The immediate response to the continuing fall in local production will be an increase in LNG imports to 2020. However, beyond 2020 a growth in pipeline supplies from Africa and the Middle East is anticipated, which acts to limit the rate of increase of LNG imports.

Russian imports are expected to show only a small decline, despite the desire by European countries to diversify gas supply. This is because of the sheer size of Russian gas resources, the gas transportation infrastructure which is configured for Russian imports, and the existence of long-term supply contracts. However, it is not possible to predict the course of geopolitical events, so there is some uncertainty about how this issue will play out.

Conclusion

The LNG market has grown strongly since 1969 (by 11.7 per cent a year), and it now represents 9 per cent of global gas consumption. Over this period Asia has consistently taken around 70 per cent of imports, with Japan and South Korea taking the largest quantities.

Australia currently exports around 24 Mtpa of LNG to Asia, which amounts to 10 per cent of global trade. However as a result of a $200 billion investment program, export capacity is expected to increase to 86 Mtpa by 2018, which will make Australia the largest LNG exporter in the world (exceeding Qatar with 77 Mtpa of export capacity). This expansion will stimulate gas demand throughout Asia, with China leading the growth in gas utilisation.

However a similar expansion of export capacity is occurring in the US and this will change the character of the market:

- the rapid growth in supply from both Australia and the US will lead to a softer market, which will put pressure on LNG prices after 2018
- US exports will utilise a new pricing paradigm linking LNG contracts to Henry Hub prices, which will be highly competitive in the Asian market
- the significant growth in LNG export capacity will increase liquidity in the global market and facilitate the continuing growth of the spot market

The major concern of customers in the Asian region has been the escalation in the price of LNG deliveries. New contract prices for LNG in Asia have diverged significantly from gas prices in the US, where the ‘shale gas revolution’ has led to prices three to four times lower than Japanese prices.

The evolution of Asian LNG prices is highly uncertain, since they are largely tied to the oil price. However recent falls in the oil price, and the increase in competition amongst LNG suppliers, suggests that new contract prices are likely to fall from their recent highs.

The LNG market after 2018 is likely to become far more competitive. Price is becoming the key determinant of future growth as customer nations seek alternative sources of supply. This includes new international pipelines, increased local production, or alternatives to gas such as nuclear power, renewables or coal.

In this context Australian LNG producers will need to focus on remaining cost competitive. Australia has significant un-developed resources, and the advantages of an experienced workforce and many potential brownfield developments. However, there is likely to be an excess of supply after 2018 for a number of years, and there are many potential new entrants which could provide sharp competition.

Australian LNG projects have a number of competitive advantages, but there is a strong incentive on all project proponents to keep costs under control.

Appendix 4a Global LNG liquefaction capacity 2014

	Nameplate Capacity (Mtpa)
Middle East	
Oman	10.7
Yemen	6.7
UAE	5.8
Qatar	77
Africa	
Algeria	19.4
Egypt	12.2
Nigeria	21.2
Angola	5.2
Equatorial Guinea	3.7
Libya	3.2
South East Asia	
Indonesia	30.2
Malaysia	24
Brunei	7.1
Russia	
Russia	9.6
North America	
USA	1.5
Australia	
Australia	24.2
Other	
Trinidad	15.4
PNG	6.9
Peru	4.5
Norway	4.2

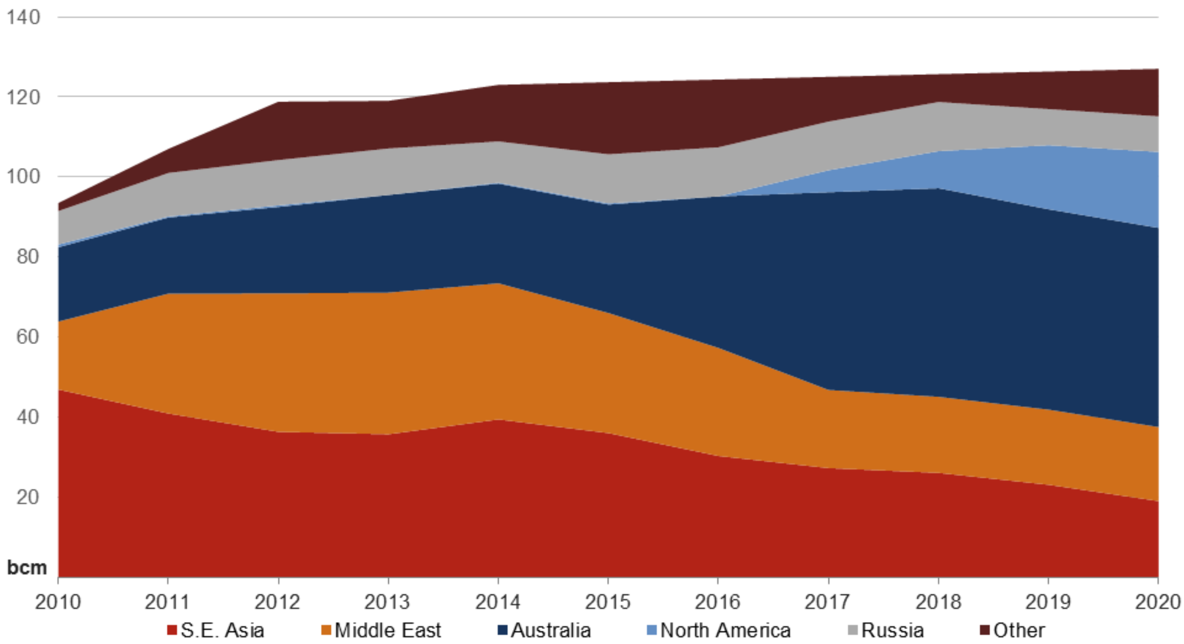
Sources: **BREE and Nexant.**

Note: that some liquefaction plants are not currently operating due to technical problems or are operating at reduced capacity due to supply shortfalls.

Appendix 4b LNG supply to Asia – *Middle East suppliers give way to Australia and the US*

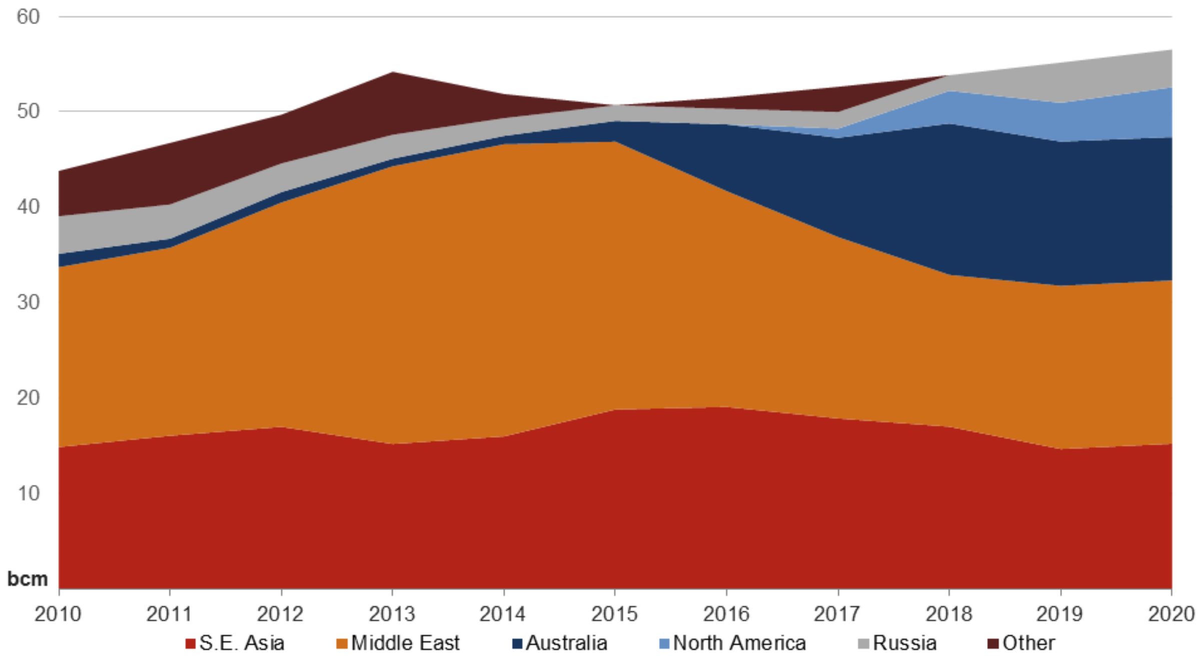
Australian LNG exports to Asia will supply the growth market in China but will also displace existing suppliers, in particular the Middle East. The global market will see a rebalancing as suppliers such as the Middle East (mainly Qatar) shift exports from North Asia to closer destinations, in particular India and Europe.

Figure 4.19 Japanese imports by source



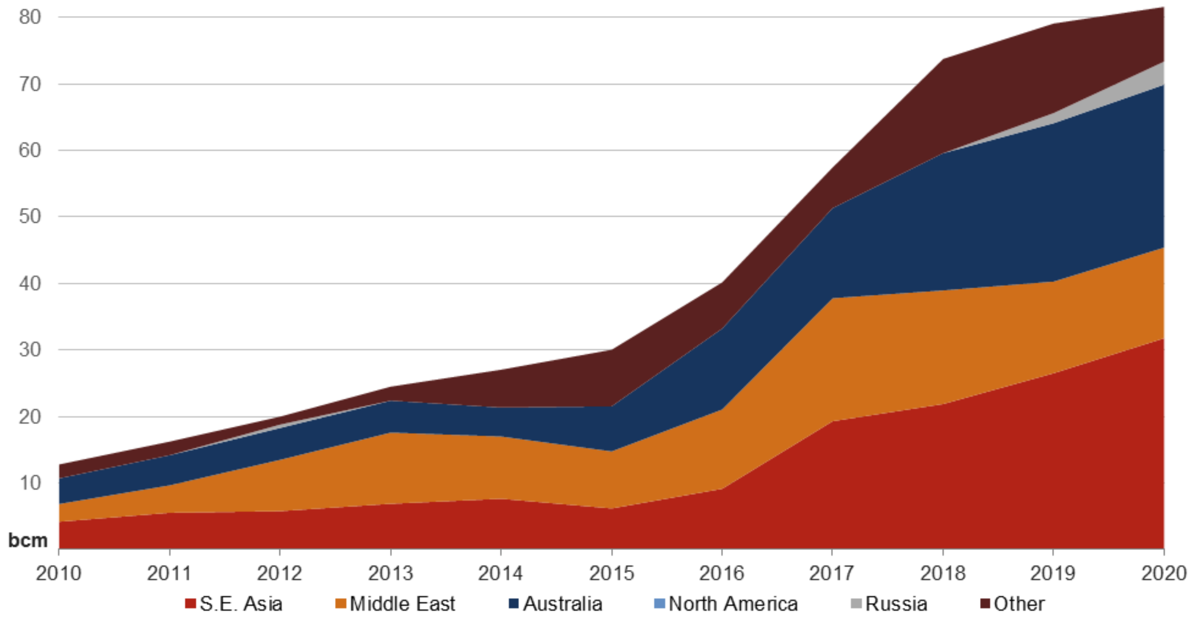
Sources: BREE and Nexant.

Figure 4.20 South Korean imports by source



Sources: BREE and Nexant.

Figure 4.21 Chinese imports by source



Sources: BREE and Nexant.

The US is also expected to take market share in Japan and South Korea, although the main impact will be after 2020. However, US exporters are well situated to supply Europe as well as Asia, so US exports to Asia will depend in part on the prospects for growth in the Europe LNG market over the next 15 years.

5 REVIEW OF THE ECONOMIC IMPACT OF THE COAL SEAM GAS INDUSTRY IN QUEENSLAND

Introduction

There is a large body of research and information on the environmental, social and economic effects attributable to unconventional gas activities both in Australia and in other countries, particularly the United States. However, a major gap in this literature is a case study that summarises at a high level what is known about the factors underlying the economic consequences arising from activities being undertaken by the coal seam gas (CSG) industry.

Queensland has experienced almost 20 years of CSG development, and more recently the establishment of a major liquefied natural gas (LNG) industry based on CSG. These together provide an opportunity to assess what is known about the state-wide and regional economic impacts associated with unconventional gas activities more broadly.

This chapter is the first part of a larger study on the economic impacts of the CSG industry in Queensland and the effects of the various stages of the CSG value chain on communities over time. This first part presents and synthesises findings from studies on the projected and actual economic impacts of the CSG industry. The economic impacts include value added as measured by Gross State Product (GSP), total employment, household income, royalties and regional population changes.

The complete study, to be published in 2015, will include a review of the effects of the CSG industry's activities that impact on the economic net benefits experienced by communities in Queensland. The second part of the study will focus on how communities experience the different stages of the CSG value chain from exploration to processing since the industry began in 1996.

The Queensland economy

As at 31 March 2014, Queensland's population was 4.7 million people, just over 20 per cent of Australia's national population. The annual growth rate in the preceding year was 1.5 per cent, the third highest of all states and territories, consisting predominantly of natural increase and overseas immigration (QGSO 2014a).

Queensland's GSP has grown at 3.6 per cent a year between 2001-02 and 2012-13, above the economy-wide GDP growth rate of 2.6 per cent. Growth was driven primarily through the mining sector, but there was also strong growth in health care and social assistance (ABS 2013a). The construction sector is the largest contributor at 10.0 per cent of GSP (including both compensation of employees as well as gross operating surplus and mixed income), followed closely by mining, which contributes 9.5 per cent. The agriculture, forestry and fishing sector contributes 3.0 per cent to Queensland's GSP (QGSO 2014c).

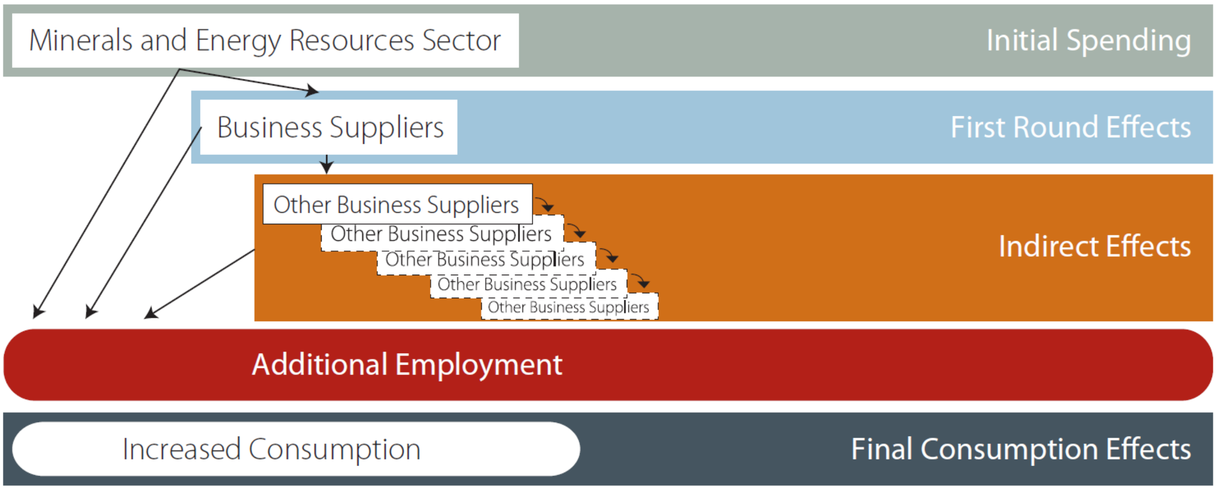
Mining royalty revenue contributed $2.1 billion to Queensland's budget in 2012-13 – 5 per cent of total revenue collected. The majority of this is coal royalties, but also includes base metals, other minerals and petroleum (Queensland Government 2014a).

Queensland's unemployment rate as of October 2014 was 6.7 per cent – higher than the national average of 6.2 per cent, which is likely a result of the slowdown in the mining sector. Although the mining sector contributes significantly to Queensland's economy and impacts on indirect employment, its share of direct employment is much smaller. Data from the 2011 census shows that mining accounted for 8.4 per cent of Australia's employment (QGSO 2014b). Queensland's mean household income is $1805 a week, similar to the national average. The mean income for Brisbane is higher than the rest of the state, at $1925 a week in Brisbane compared to $1359 elsewhere (ABS 2013b).

The economic contribution of the resources sector in Queensland

Queensland is a diverse economy, and mining plays a very important role. As noted above, it contributes almost 10 per cent of GSP but makes up almost 50 per cent of Queensland's exports (QGSO 2014c, 2014d). The various mining booms over time have shaped Queensland's economy and many of the communities within it. As shown in figure 5.1, the minerals and energy resources sector can have a large range of impacts on local and regional communities across Queensland, including direct and indirect effects (Rolfe et al. 2011).

Figure 5.1 Structure of economic impacts of the resources sector



Source: Rolfe et al. 2011, in Williams et al. 2013.

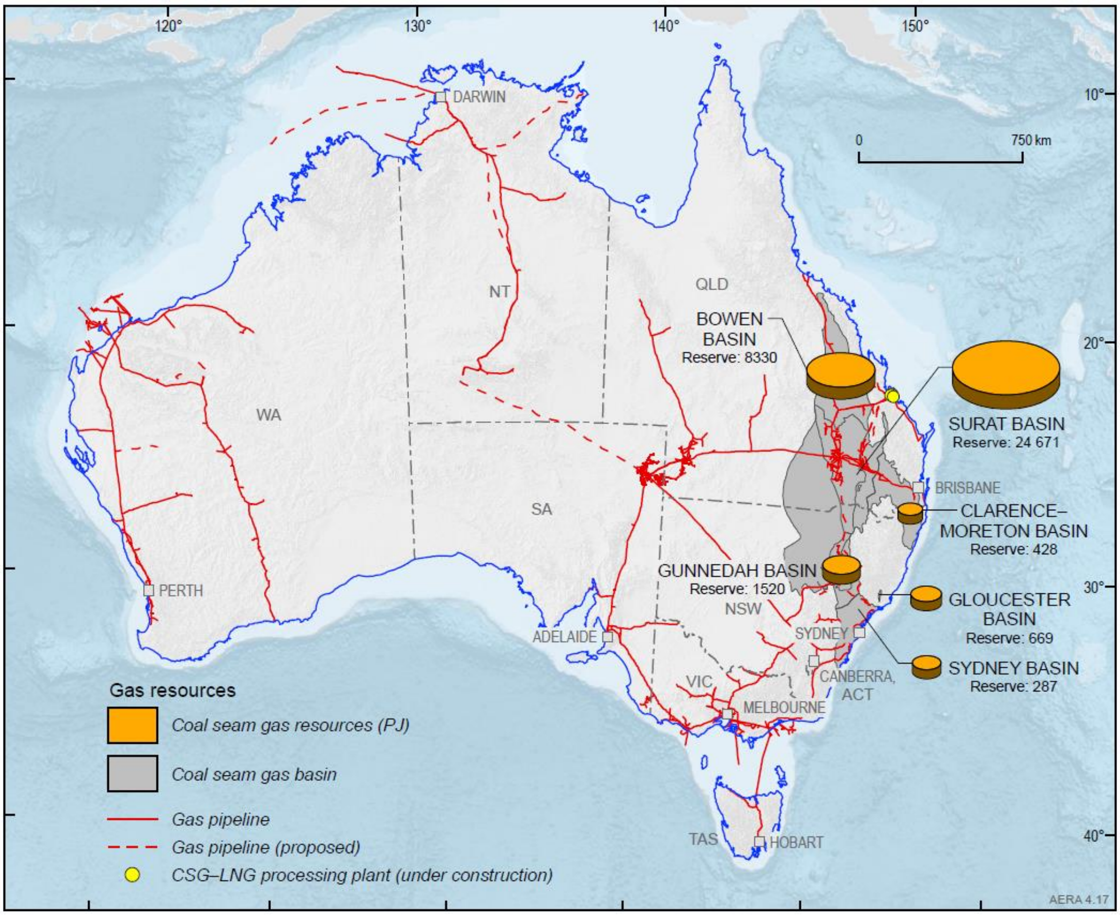
Rolfe et al. (2011 p.15) considered four key variables of output, income, employment and value added, and found that incomes and expenditures from the resources sectors are widely distributed across the state, and generate significant flow-on effects, much of which flows to South East Queensland, particularly Brisbane. This is supported by extensive studies undertaken on the economic impacts of mining booms, both in Queensland and more broadly, which detail generally positive impacts, although many of these studies do not address the distribution of these impacts and how they impact on individuals within communities.

CSG development

International technologies for unconventional gas were applied in Queensland as conventional gas resources supplying gas to the state were starting to deplete. These developments encouraged a wave of exploration as the potential for the development of Queensland's CSG resources became apparent.

Figure 5.2 shows the distribution of Australia's CSG reserves, the bulk of which are located in Queensland's Bowen and Surat basins, while smaller reserves are located in the Clarence-Moreton, Gunnedah, Gloucester and Sydney basins in New South Wales.

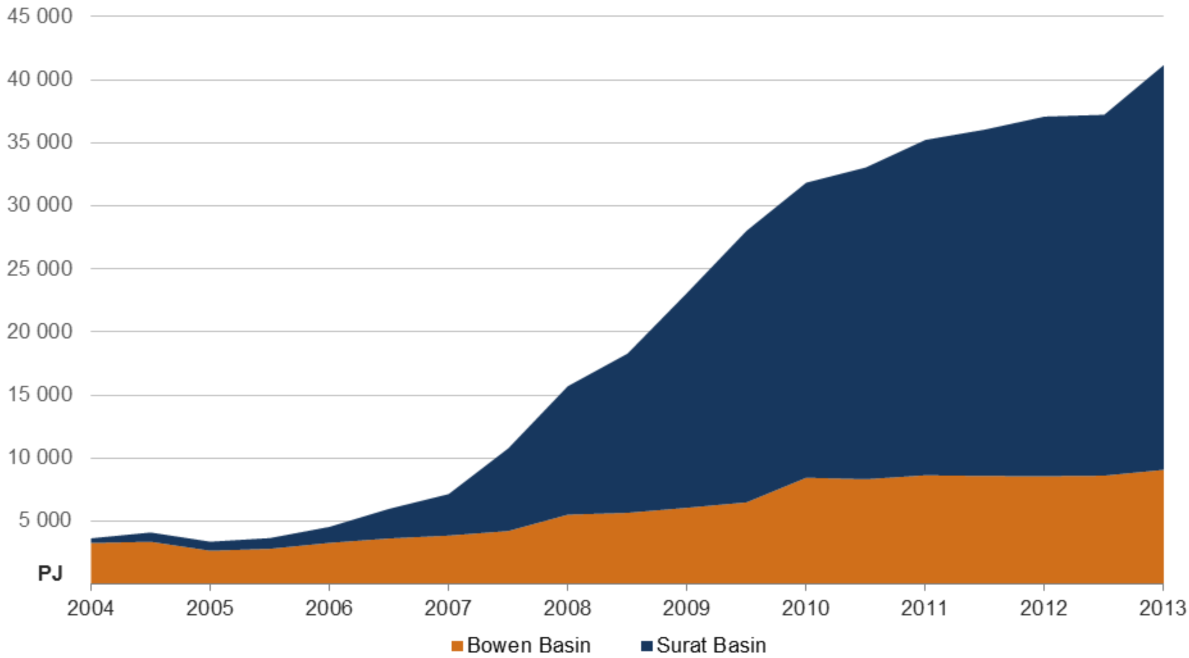
Figure 5.2 Australia's coal seam gas reserves and gas infrastructure



Source: Geoscience Australia, January 2012.

The CSG industry has been operating in Queensland since 1996, when commercial CSG production commenced near Moura in the Bowen Basin. Figure 5.3 illustrates the growth in Queensland's CSG reserves since December 2004, when 2P reserves (proven and probable) were around 3650 petajoules (PJ). Over the 8 years to 2013, 2P reserves have increased more than tenfold to 41 170 PJ, predominantly in the Surat Basin.

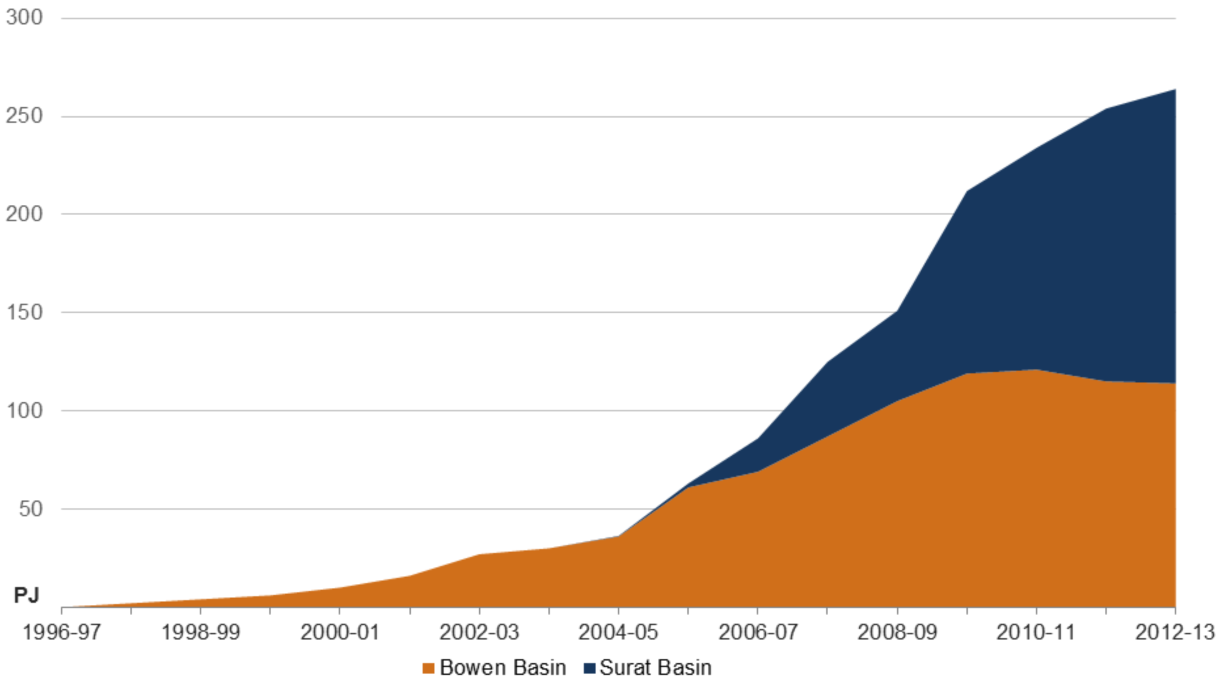
Figure 5.3 Queensland coal seam gas 2P reserves (proved and probable)



Source: Queensland Government Department of Natural Resources and Mines.

The increase in reserves has been accompanied by an increase in production, as shown in figure 5.4. When CSG production commenced in the late nineties, it produced only three per cent of Queensland's gas, but with 264 PJ of production in 2012-13 it is now the dominant source of Queensland's natural gas, at 89 per cent.

Figure 5.4 Queensland coal seam gas production



Source: Queensland Government Department of Natural Resources and Mines.

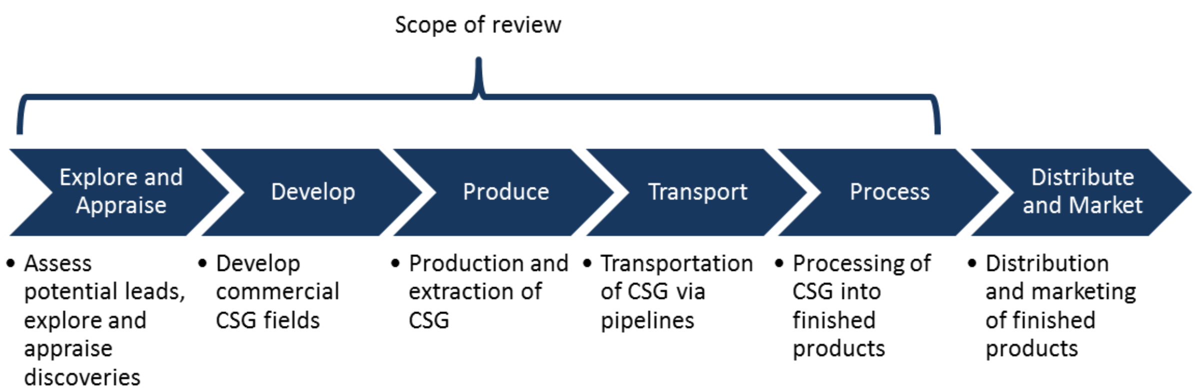
Queensland Government policies have also supported the development of the gas sector, including through the Queensland Gas Scheme, which began in 2005 and was designed to boost the industry and reduce greenhouse gas emissions. It required electricity retailers to procure a certain percentage of their electricity from gas powered generation (Queensland Government 2014b). The scheme was closed at the end of 2013, at which point gas powered generation had exceeded the target of 15 per cent and reached almost 20 per cent of Queensland's electricity generation, up from only 2.4 per cent of generation when the scheme was introduced in 2005 (Queensland Government 2014c).

Assisted by the Queensland Gas Scheme and the growth of gas powered electricity generation, Queensland's CSG production increased rapidly after 2005. Coinciding with increasing LNG demand and prices in Asia, a number of gas producers saw opportunities to utilise Queensland's CSG reserves for LNG export. From a large range of proposals under consideration, three LNG export projects proceeded to final investment decision and are currently under construction. The three projects have a combined capacity of over 25 million tonnes per annum, larger than Australia's current total export capacity, and more than double the existing eastern Australian gas market. The three projects will be the first ever CSG to LNG projects in the world:

- Queensland Curtis LNG (QCLNG) – operated by BG Group in a venture with CNOOC and Tokyo Gas, QCLNG will have a capacity of 8.5 million tonnes per annum (Mtpa) from two trains, and is scheduled for first gas before the end of 2014
- Gladstone LNG (GLNG) – operated by Santos in partnership with Petronas, Total and KOGAS, GLNG will have a capacity of 7.8 Mtpa from two trains, and is scheduled for first gas in 2015
- Australia Pacific LNG (APLNG) – operated by Origin Energy (upstream) and ConocoPhillips (downstream) in a venture with Sinopec, APLNG will have a capacity of 9 Mtpa from two trains, with first gas expected in 2015

The production of CSG differs from that of conventional gas, as the gas cannot easily move through the coal seam formation. Instead, it requires the extraction of water from the coal seam to reduce the pressure and allow the gas to be released from the coal seam. CSG extraction usually requires a larger number of wells than conventional gas production (CSIRO 2013). The different stages of the CSG value chain are shown in figure 5.5 below, which highlights the scope of the review.

Figure 5.5 Stages of the CSG value chain and the scope of the review



Source: Adapted from AIRBUS Defence and Space (n.d.).

This growth and transformation in Queensland's gas industry has not been without challenges. Community concerns have emerged with regard to environmental, economic and social impacts of the CSG boom, given it is a new technology and it is occurring in areas which often overlap with existing land uses, including agriculture. The Queensland Government responded by introducing policies to regulate the CSG exploration and production industry and address community and environmental concerns. This includes a range of regulatory instruments specific to the CSG industry with regard to water management, gas gathering, construction and abandonment of wells, and emissions detection and reporting, in addition to the standard legislation which applies to the gas industry with regard to exploration and production activities, safety, environmental impacts, and water management.

Studies of CSG impacts

The ramp up in LNG production is projected to increase Queensland's economic growth through the increase in exports of LNG and the indirect effects of the construction and operation of the three LNG projects (Nicholls 2014). There is a substantial body of literature which assesses the potential economic impacts of the CSG industry and the associated LNG export projects in Queensland. This case study aims to synthesise these studies to assess the overall impact of the CSG industry on the state.

The first part of the study, as presented in this chapter, surveys and reviews the results of studies that have predicted or assessed the headline economic impacts of the CSG industry in Queensland. With reference to the CSG value chain set out in figure 5.5, this review focuses on the upstream and mid-stream stages of the value chain through to gas processing. However, many studies include the total impact of CSG and LNG projects together, so LNG impacts have been included where relevant.

Predicted impacts of the CSG industry

As required under Queensland's legislation, each of the proponents of CSG projects have undertaken a detailed assessment of the economic impacts of their projects as part of the Environmental Impact Assessment process. Although the requirements have changed over time, the proponents were generally required to assess most of the following issues:

- The relative significance of their proposals in the local, regional, state and national economic context
- The extent to which local and other Australian goods and services would be used
- The short and long term beneficial (e.g. job creation) and adverse (e.g. competition with local small business) impacts that were likely to result from the development
- The need for any additional infrastructure provision by the government to support each project
- Implications for future development in the locality including constraints on surrounding land uses and existing industry
- The impact on living standards at the local, regional and state level

- The potential impact on the domestic gas market and domestic gas prices

All three projects currently under construction undertook economic studies of the impacts of the projects utilising Computable General Equilibrium (CGE) models to capture the inter-linkages between sectors of the economy and the price impacts of the various factors of production such as labour.

Broadly, these economic studies found that the projects would provide net economic benefits to the Queensland economy. In particular, the studies project increases in GSP and employment associated with the developments, mostly in the construction phase of the projects. The key outcomes for each project are:

- QCLNG – an additional $32 billion in GSP over the period 2010 to 2021, or an additional 1.3 per cent of GSP, with construction contributing $2.4 billion and operations $29.5 billion; an increase in employment of 60 000 full time equivalent over 12 years and additional state revenue of $150-300 million a year
- GLNG – an additional $4.1 billion a year in GSP on average over the period 2009-33, an additional 1 per cent of GSP and more than 3000 direct jobs created with an additional 1500 jobs in the development of the gas fields
- APLNG – an additional $2 billion a year in GSP on average, 5000 construction jobs and 1000 operations jobs and additional state revenue of $485 million a year

Although the Arrow LNG Plant is still awaiting final investment decision, the economic impact assessments for the LNG plant and the associated Surat Gas Project and Bowen Gas Project, which also used CGE analysis, found a range of similar impacts.

A number of other organisations, including the Queensland Government and industry and community groups, also commissioned their own studies, particularly when the potential extent of the impact – given the simultaneous construction of three export projects and the exposure to the LNG export market – became clear. A number of academic research papers have come to similar conclusions that CSG development will have positive economic and distributional impacts. However, large domestic gas users have raised concerns about the impacts of the alignment of the east coast gas market to the international LNG market on the price and availability of gas and the subsequent effect on their operations.

Actual impacts of the CSG industry

There have been a number of studies undertaken on the actual impact of the recent phase of CSG development thus far. Most of the findings from studies of the actual economic impact of the CSG industry are consistent with the effects on headline economic indicators anticipated in the ex-ante studies.

A useful comparison over time is the data which the Queensland Resources Council (QRC) has been collecting since 2010-11 from its member companies, regarding expenditure on goods and services, employee salaries and wages, and voluntary community contributions by postcode. Through the analysis of this data, Lawrence Consulting (2013) found that there was particular growth in 2012-13 in the Darling Downs and Surat - largely due to growth in CSG activities. In terms of sectors, the impact of CSG is second only to coal in terms of value added, employment, business spend, and wages and salaries.

A number of other studies have focussed on particular aspects of the economic impacts of CSG development, including several by the Gas Industry Social and Environmental Research Alliance (GISERA), an alliance currently consisting of CSIRO, APLNG and QGC. In addition, the Queensland Government Statistician's Office (QGSO) makes regional profiles available of the Bowen and Surat basin resource regions, which provide demographic, social and economic data on these regions over time.

Economic contributions of CSG in Queensland

The focus of this review is on the headline economic impacts of the CSG sector, with the next stage of the review to consider the socioeconomic impacts and the ways in which communities experience the effects of CSG. The headline economic impacts which are most commonly cited as impacts of the CSG industry include:

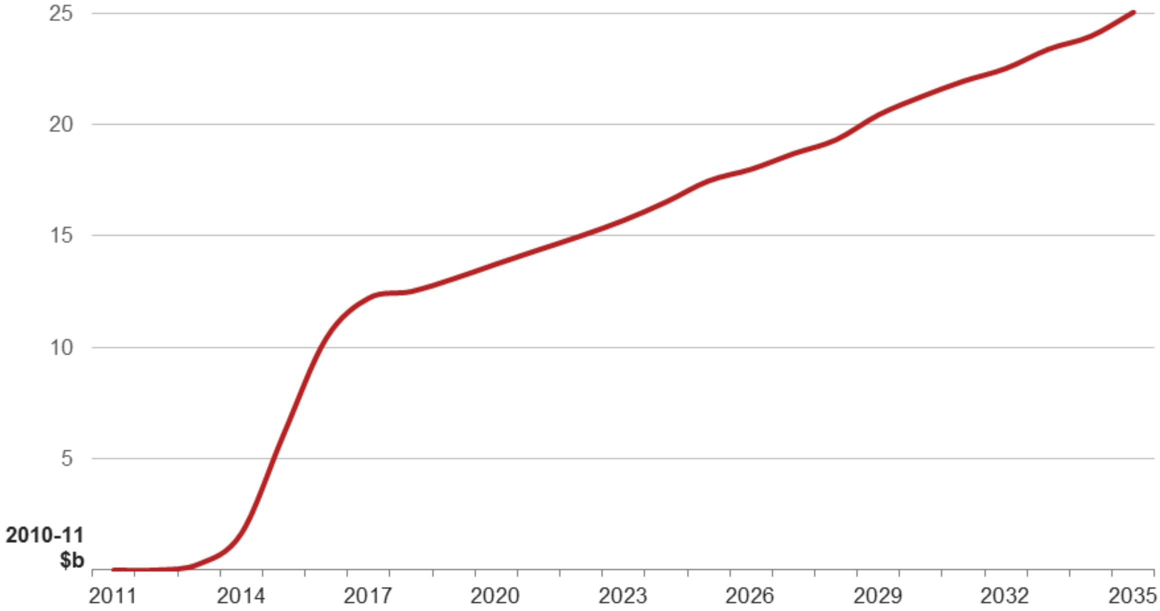
- value added (the total value of goods and services produced in Queensland less the cost of inputs) as measured by GSP
- employment, both in terms of direct employment by CSG companies and indirect impacts on broader employment in the state
- household income as an indicator for wealth, including all forms of income for people in a household
- royalties and other government revenues
- regional population changes

It is often difficult to separate the impacts of the CSG and LNG developments into the various components of the CSG value chain. Early studies focussed particular attention on the impacts of LNG exports rather than disaggregating these impacts into the various stages of the value chain. Where possible, this review attempts to separate the effects, but they are most often conflated in forecasts of economic impacts.

Gross State Product

Forecasts of the impact of CSG development on Queensland's GSP were consistently positive, both in terms of direct and indirect effects or multiplier effects of the flow-on impacts of the CSG industry to other sectors. Much of the GSP growth was forecast to come from industries which supply the oil and gas sector, including construction, other mining, transport and hospitality, whose output is non-tradable. Offsetting the benefits to some extent were industries forecast to suffer losses as a result of the growth in CSG, including tradable sectors where there is competition from international suppliers, such as manufacturing and agriculture. ACIL Tasman (2012) forecast that the cumulative impact of a six-train LNG export industry on Queensland's GSP would peak at around $25 billion in 2035 (see figure 5.6).

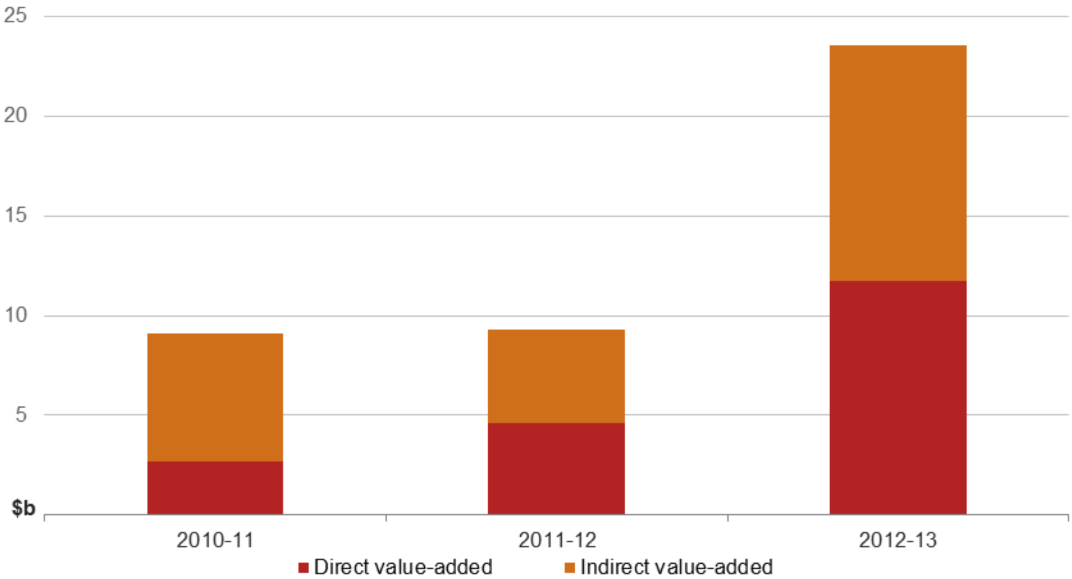
Figure 5.6 Forecast contribution of LNG exports to Queensland's Gross State Product



Source: ACIL Tasman (2012).

A review of the Lawrence Consulting analysis of QRC data since 2010-11 illustrates that the forecast growth in the contribution of the CSG sector to Queensland's GSP has commenced. In 2012-13, both direct value added (including salaries to direct full time employees, purchases of goods and services and community contributions), and second round value added (supply chain and consumption effects) from the CSG sector are over $11 billion each, providing a total contribution to GSP of $23.6 billion as shown in figure 5.7.

Figure 5.7 Modelled contribution of the coal seam gas sector to Queensland's Gross State Product



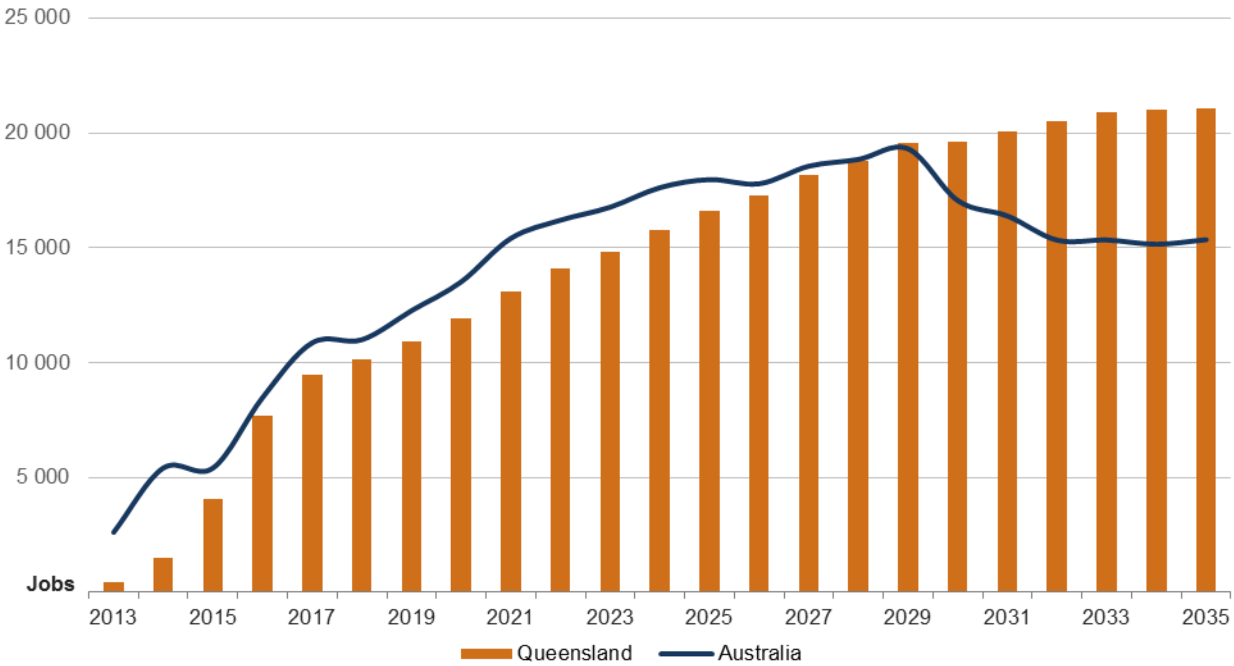
Sources: Lawrence Consulting/Queensland Resources Council (2014).

Some large gas users argue that the indirect impacts of their industries are larger than the indirect impacts of CSG export and argue that the gas would be better reserved and used domestically. However, no study has compared the two scenarios using consistent methodology that comprehensively captures the economy-wide impacts.

Employment

Studies on local economic impacts associated with the mining industry more broadly have found that in an average region if the number of miners doubles, non-mining employment is expected to grow by four per cent (Fleming 2014). Forecasts of employment in Queensland in advance of the recent phase of CSG development were consistent with this, predicting large increases in both direct employment (new jobs in the CSG sector) and indirect employment (additional jobs in other sectors as a result of the CSG boom). For example, ACIL Tasman (2012) estimated an indirect impact averaging around 14 242 FTE jobs each year to 2035 of a scenario involving six trains of LNG export capacity in Queensland, although this is offset by a decrease in employment in the rest of Australia (see figure 5.8).

Figure 5.8 Modelled contribution of the coal seam gas sector to employment



Source: ACIL Tasman (2012).

Consistent with these predictions, a range of subsequent studies have found strong evidence that the growth of the CSG industry has provided increased direct employment and indirect employment effects, particularly to the construction and professional services sectors:

- Economic data from QGSO (2014d, 2014e) shows a strong growth in employment in the CSG resource regions between the 2001 and the 2011 census (2014d, 2014e). Although this growth cannot be attributed purely to the growth in the CSG sector, the unemployment rate in the Surat Basin decreased from 5.9 to 3.1 per cent, and in the Bowen Basin from 4.3 to 2.2 per cent. This growth in employment is even stronger when considering purely the change in the mining sector. Over the same period, growth of employment in the mining sector has grown by 122 per cent in the Bowen Basin (from 21 to 32 per cent of the workforce), and by 575 per cent in the Surat Basin (from a lower base – from 1.3 to 7.2 per cent of the workforce), although this data encompasses the broader mining sector and not just the CSG industry (QGSO 2014)

- KMPG analysis of the census data found that the percentage of people working in the oil and gas sector alone in the Surat has increased by 273 per cent between the 2006 and 2011 census (2013)
- An analysis of the census data by Fleming and Measham (2014) found that employment in the mining sector shows higher growth in areas with CSG development compared to the rest of Queensland. Employment in the Surat Basin has grown more than in the Bowen, signalling that the positive employment effects are stronger in areas without a history of mining. From a closer examination of the Surat Basin, there was mixed evidence of spillover effects of employment into other industries. The expected broad range of positive job multipliers were evident only in the construction and professional services industries, but not retail trade or other local services
- Lawrence Consulting's analysis of QRC data found that the total employment impact of the CSG and LNG industry, including the modelled indirect FTE, increased from 1.5 to 4.9 per cent of regional employment between 2010-11 and 2012-13, reaching a total of 115 190 employees

Increases in employment were anticipated to have large economic impacts on regional communities, as employees to fill newly created positions were required. In advance of the boom, proponents expected new jobs in the CSG sector to be filled predominantly by workers from:

- outside the region (either to be temporarily located in worker camps or to commute in and out of the region)
- local populations, either through reducing the unemployment rate, bringing additional people into the workforce, or through workers leaving other sectors, particularly agriculture and manufacturing

A number of proponents noted that the participation rate in the gas fields' regions was quite low and there would be capacity for a number of individuals to join or re-join the workforce.

There is evidence that some of the employment in the CSG sector has been drawn from other industries, as the growth in employment in CSG has been associated with a reduction in agricultural employment. Fleming and Measham (2014) found evidence that agricultural jobs have been affected negatively – 1.8 agricultural jobs lost for every CSG job created – which could be because of direct moves into mining jobs, or also because high labour costs have encouraged a move towards less labour-intensive agriculture. However, contrary to expectations, there was no significant loss of jobs in the manufacturing sector as a result of the growth of the CSG industry.

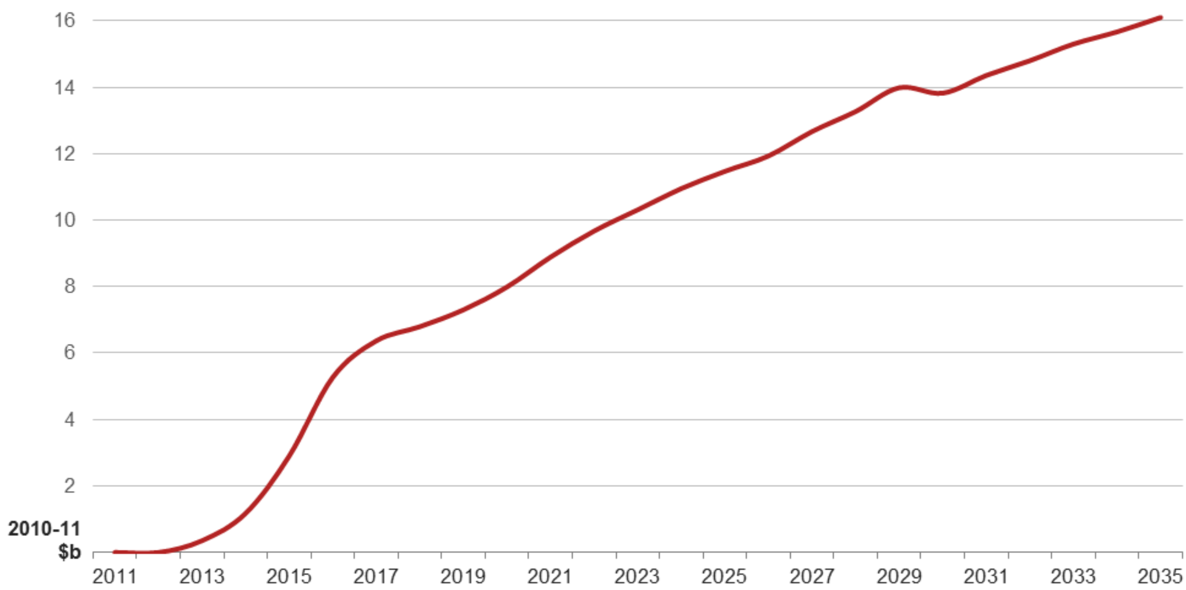
Household income

Household income is generally expected to increase as a result of a mining boom in an area. Fleming (2014) found that a doubling of the number of miners in a region is expected to lead to 2 per cent growth in family income in that region.

Each of the project proponents forecast an increase in wages, although the impact is likely to vary over the different regions depending on the size and composition of the local workforce and the size and skillset of the additional workforce required. Although not disaggregated to industry level, KPMG found a large proportion of residents with a high income in the Bowen Basin (2013). In both the Bowen and Surat basins, the proportion of high income residents had grown between the 2006 and 2011 census, increasing two fold in the Bowen.

Although not all of the earlier studies forecasting CSG impacts explicitly covered household income, those that included the indicator expected it to be positive. ACIL Tasman (2012) forecast that the cumulative impact of a six-train LNG export industry on Queensland's real income would peak at around $16 billion in 2035 (see figure 5.9). This is lower than the forecast impact on GSP, as not all of the increased output will flow to Queensland residents.

Figure 5.9 Modelled contribution of the CSG sector to real income



Source: ACIL Tasman (2012).

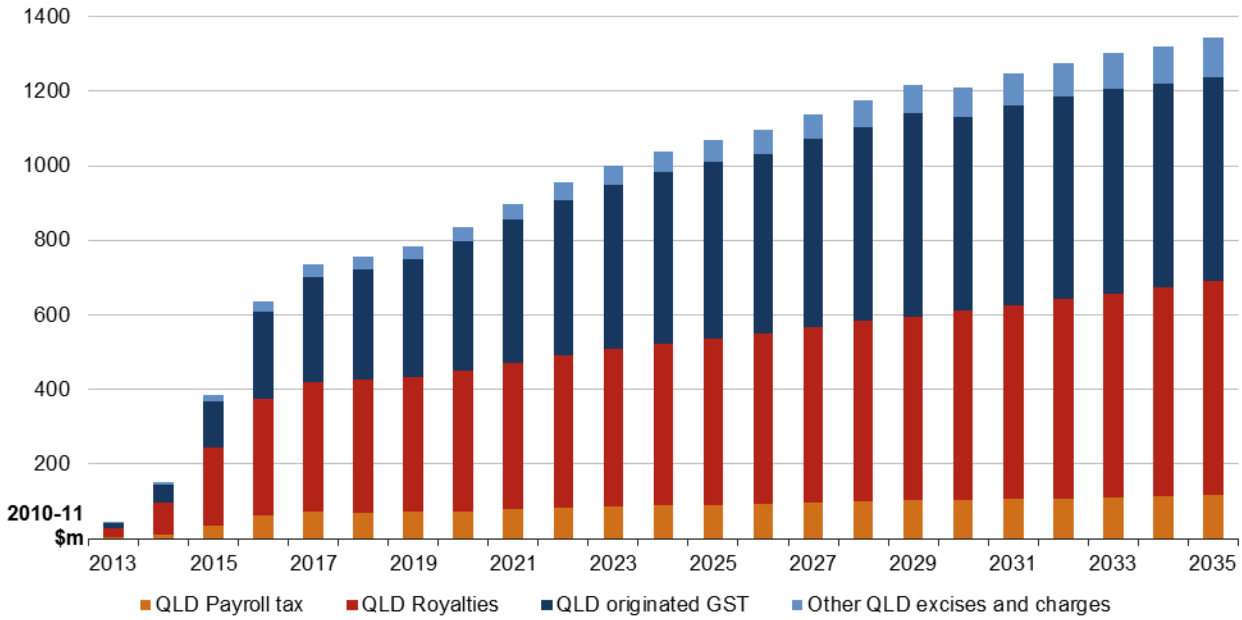
Fleming and Measham's (2014) investigation of economic outcomes related to the CSG industry across southern Queensland (2014) found that areas with CSG development showed higher income growth than those without it during 2001-2011. Over this period, family income grew by 12 to 15 per cent more in areas of CSG activity than in the rest of Queensland. This provided evidence that CSG development was associated with higher income growth and this growth was not restricted to workers residing temporarily in CSG regions. The income growth was also shown to be benefiting the region, as the income effect also applied to local residents.

However, offsetting this increase in household income to some degree, were forecasts in most of the studies of an increase in the cost of living. It was broadly acknowledged that costs of services and some goods would increase as a result of increased demand and pressures on labour costs for businesses. There were also some concerns that the bulk of income growth would go to workers commuting from other regions, rather than benefiting the local communities. However, there is very little information regarding the actual distribution of the income effects and any resulting income inequality in these areas.

Royalties

State and Commonwealth government revenues were both expected to see a boost from increased CSG production. Project specific revenue to the Queensland government is expected to be between $150 and $500 million per LNG project, while revenue to the Australian government is estimated at around $200 to $300 million. The annual cumulative impacts from the CSG and LNG activities of the six train scenario modelled by ACIL Tasman (2012) averaged to around $900 million each year to the Queensland Government, consisting of royalties, taxes, excise and charges, and an average of $2.4 billion each year to the Australian Government in company and personal income taxes (see figures 5.10 and 5.11).

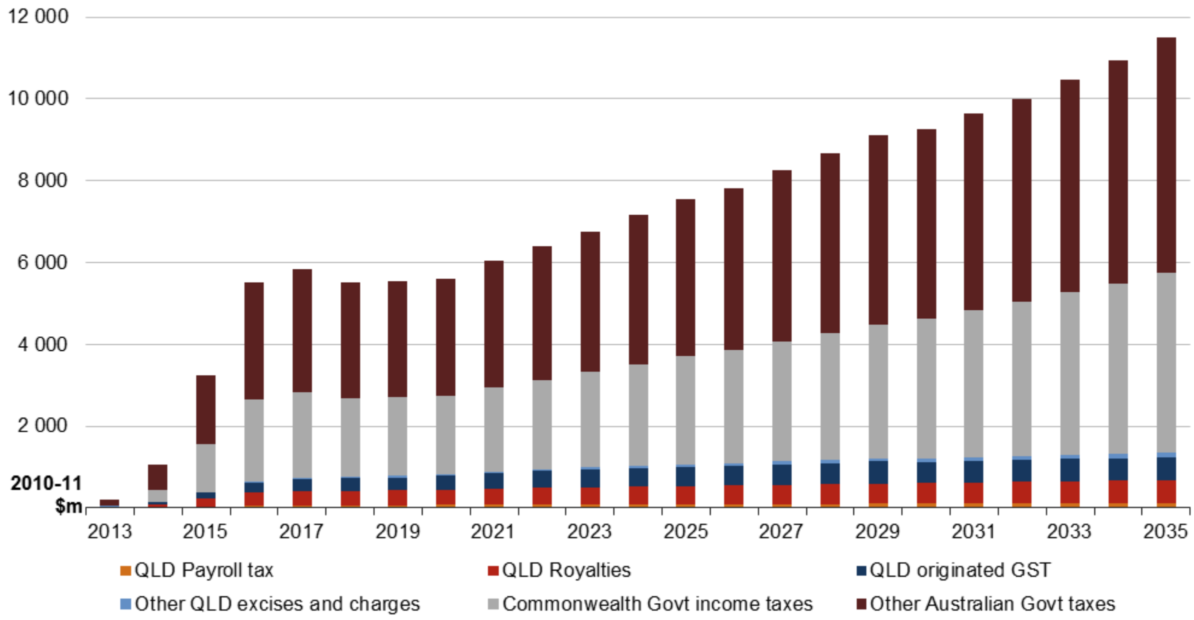
Figure 5.10 Projected change in Queensland Government revenue



Source: ACIL Tasman (2012).

At this stage, there is evidence of a small increase in royalties and other government revenue from the growing CSG production for the domestic gas market, but the expected spike in government revenue as a result of CSG exports revenue is not forecast to occur until 2014-15. Queensland's royalty collection fell in 2012-13 as a result of a drop in coal prices, however the royalty collection from petroleum, a growing proportion of which is CSG, increased by 11 per cent since 2011-12 (Queensland Government 2014a). The Queensland Government (2014e) estimates that the peak growth in LNG production in 2015-16 will lead to a 36 per cent growth in royalty revenue in that year.

Figure 5.11 Projected change in Australian Government revenue



Source: ACIL Tasman (2012).

Any flow-through impacts on communities from increased CSG will take some time, although the Queensland Government has already committed to invest royalty earnings into infrastructure projects for communities through the Royalties for Regions program.

Population

The project proponents did not envisage a large increase in permanent populations of the areas impacted by CSG and LNG developments, rather they anticipated that the parts of the workforce not met by local residents would instead commute to the region and be accommodated in work camps. Given this was already an established practice in the mining sector, particularly in the Bowen Basin, project proponents expected that the demand for additional services in regions would not be significant, although they acknowledged that additional short term accommodation may be required.

Actual observations of changes to population are consistent with forecasts that the CSG industry would rely significantly on temporary workers based in camps for peak construction employment. The QGSO data (2014d, 2014e) shows that growth in the resident population (excluding workers who commute to and from the region) of the Bowen Basin has grown by an average rate of 1.6 per cent between 2001 and 2013, and by 1.2 per cent in the Surat Basin. This is lower than the population growth across the whole of Queensland of 2.2 per cent over the same period, although the growth in the Bowen and Surat basins has sped up in the past few years, at 2.3 per cent and 1.5 per cent respectively, relative to a growth rate of 2.0 per cent across Queensland as a whole.

As a result, the regional economic growth may be limited as commuter workers take much of their income out of the region. Rolfe (2013) found that positive impacts of resource projects on economic growth in the Surat Basin are very sensitive to the extent that the existing workforce can be utilised and to the level of non-resident workforce based outside the region - if workers commute the positive impacts will be much smaller.

Although proponents have built camps to accommodate many of the workers from outside the region, accommodation still needs to be found for workers in the industries which supply the oil and gas sector. Increases in resident and non-resident population have the potential to place additional pressure on housing and land availability, particularly during peak construction periods where the market is particularly tight. There has been little investigation of the impact of the CSG industry on housing availability and property values thus far.

New South Wales Land and Property Information (2014) found that there are elements of the CSG industry which have the potential to impact property values both positively and negatively, including positioning of wells, landholder compensation, environmental impacts, and community perceptions. The study found no evidence of impacts on land values in the limited number of property sale transactions available, but anecdotal evidence suggested a reduction in the number of potential buyers and a longer time taken to sell. RP Data (2013) found that the housing markets within regions where AGL is active have generally shown similar or superior performance with regard to median house price growth compared with surrounding regions. With respect to Queensland, KPMG (2013) found that despite high incomes in the Bowen and Surat basins, levels of home ownership have dropped.

Insights on the economic impact of the CSG industry

Broader impacts of resource extraction

In their categorisation of resource extraction impacts, Measham and Fleming (2013) concluded that the main initial economic impact of a resources boom is the increase in labour demand associated with the new industry. As a consequence of this labour demand, three direct impacts will emerge:

- local wages will increase as more labour is demanded
- there will be an increase in the demand for services and non-tradable goods
- there will be a movement of labour from manufacturing and/or agriculture to the resources sector

In addition, there is a range of indirect effects which may or may not occur in a specific community depending on its individual characteristics, including regional immigration, a reduction in housing affordability, a reduction in agricultural outputs, and the potential closure of manufacturing firms. Fleming and Measham (2013) also set out the way these impacts can materialise at the regional level, including:

- generation of employment and increased income
- increased population in the region through attracting new workers
- higher levels of consumption and increased demand for local goods and services
- job spillovers in certain other sectors, particularly in accommodation, restaurant services, local services, public jobs and construction

- potential crowding out of employment in other sectors, such as local manufacturing and agricultural employment
- boomtown impacts on regions, including loss of entrepreneurship, reduced affordability, potential poverty for locals outside the mining sector, and increased male population (potentially leading to alcoholism, drug abuse and violence)

Forecast impacts

The impacts forecast in the CSG industry studies prior to the current expansion are broadly consistent with the impacts that are expected in a resources boom – increased employment and income, including spillovers to other industries; increased population in regions (although much of this was forecast to be temporary through non-resident workers); increased demand and consumption throughout Queensland; and some level of crowding out of other sectors, including agriculture. Although not explicitly set out in many of the studies, predictions of the impact of CSG developments noted that there was some risk of boomtown effects on regions, particularly reduced affordability for members of the community.

However, there were not many studies which predicted the cumulative impacts of CSG development on the Queensland economy. Much of the literature on the economic impact of the broader resources sector has flagged the importance of assessing cumulative impacts, not just in terms of multiple resource projects but also in terms of the cumulative impacts of all land uses (Uhlman et al. 2014, CSRM 2013, de Rijke 2013, Franks et al. 2013, Porter et al. 2013, Williams et al. 2012). Although many of these studies refer to cumulative socioeconomic impacts and will be considered more fully in the second part of the CSG industry impact study, it is also important to consider the cumulative effects when considering headline economic indicators.

Many of the early studies that forecast impacts were undertaken in advance of final investment decisions on the three LNG projects currently under construction, and did not envisage the current scenario of multiple LNG projects under construction and the additional pressures on the demand for labour and capital in Queensland which could result. This includes the Queensland Government study commissioned in 2007, and individual project proponents who were confident of their own project going ahead, but expressed doubt that the projects would be developed simultaneously, given uncertainties regarding the economic outlook in the wake of the global financial crisis. The actual extent of development vastly exceeded expectations, with over 25 Mtpa of export capacity currently being constructed simultaneously.

Reports at later stages, including ACIL Tasman's modelling for APPEA, were drafted after final investment decisions were taken on the three projects currently under construction. The ACIL Tasman report, although it considered the cumulative impacts of a six-, eight- and ten-train CSG to LNG development, included some optimistic production and cost curve assumptions that allow for expansion to ten trains while having additional production available to supply domestic customers in all scenarios.

No robust analysis was done in advance of the recent CSG industry expansion of the cumulative general equilibrium effects of the CSG industry and associated LNG projects which included a variety of sensitivities, such as well productivity and regional LNG prices. Although the Queensland

Government requires that the environmental impact studies undertaken by proponents look into the cumulative effects of developments in a region, this was by its nature cursory, given proponents will only have limited details on each other's projects. Each of the proponents used CGE modelling to assess the impact of their project, and some of the project proponents included sensitivities in their analysis in relation to price assumptions, cost assumptions, and greenhouse gas emission policies and associated permit prices. Other analyses noted some of the risks to their forecasts, including potential downside risks on CSG reserves or production rates. In addition to these studies, an independent analysis of the cumulative impacts would have been useful.

Actual impacts

Studies of the actual economic impacts of the CSG industry in Queensland have shown that CSG provides a clearly positive net benefit to Australia, Queensland and affected regions. However, the key issue which has not been fully evaluated is the distribution of the benefits and costs, which can be unevenly distributed between regions, and also within communities amongst those involved in the industry and those outside it.

There is a broad range of socioeconomic factors which have a material impact on the net benefit of the CSG industry to the Queensland economy and the regions within it, and the impact of the industry may differ significantly from the impacts of previous mining booms. Research into the distributional effects of the CSG industry, bringing together the economic and social impacts of the development of the industry, would provide greater depth in understand the impacts of these developments. It would also ensure that government, industry and the community had the information available to best manage the overall impacts of the CSG industry.

BREE (as part of the Office of the Chief Economist in the Department of Industry) will continue to assess the literature on the key effects on communities that are not captured by economic impact assessments, including health impacts, land access and usage, impacts on water, transport nuisance and noise pollution, in the second part of this assessment of the socioeconomic effects of CSG in Queensland, which will be published next year.

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6 A NOTE ON THE ECONOMICS OF DOMESTIC GAS RESERVATION POLICY

Introduction

This note presents an overview of the economics of domestic gas reservation policy based on a review and synthesis of the following studies relating to Australia:

- ACIL Allen's 2014 report to the Economic Regulation Authority of Western Australia
- BIS Shrapnel's 2014 report to the Australian Workers' Union
- Deloitte Access Economics' 2013 report to the Australian Petroleum Production and Exploration Association (APPEA)
- Deloitte Access Economics' 2014 report to the Australian industry Group, the Australian Aluminium Council, the Australian Food and Grocery Council, the Australian Steel Institute, the Energy Users Association of Australia and the Plastics and Chemicals Industries Association
- EnergyQuest's 2013 report to APPEA
- Haylen and Montoya's 2013 NSW Parliamentary Research Service briefing paper
- Hogan and Thorpe's 2008 ABARE report for the Australian Government Department of Resources, Energy and Tourism
- National Institute of Economic and Industry Research's 2012 report to the Australian Industry Group and the Plastics and Chemicals Industries Association

The objective of this note is to provide general insights on the economics of gas reservation and how it affects gas users, producers and government revenues. It also considers gas market interventions that have been adopted internationally and in Australia.

Domestic gas reservation policies

There are several types of gas reservation interventions commonly applied by governments:

- Domestic production obligation, such as used in Western Australia, which secures from the producer a guaranteed percentage or set volume of gas for domestic consumption
- Acreage reservation, which reserves certain areas with prospective gas resources for domestic consumption only
- Export control, which requires a licence for exporting gas that is granted subject to the application satisfying conditions, such as a national interest test

The objective of these policies is to put downward pressure on gas prices for domestic gas users by diverting to the domestic market some gas that would otherwise be exported.

In general, a domestic gas reservation policy impacts on the domestic price of gas when the netback price calculated at the feed-in to the LNG plant is higher than the price of gas that would prevail if it was determined solely by the domestic market.[1] When a reservation policy affects domestic gas prices it does so by placing an implicit tax on gas producers that, rather than going to the government, provides domestic gas users with a price subsidy. In such a case, under a reservation policy domestic gas prices will be lower than otherwise and, in the absence of any other unfavourable factors, industries that would be economically unsustainable if the price of gas was not subsidised may remain commercially viable.

International use of domestic gas market interventions

EnergyQuest (2013) reviewed the effectiveness of government domestic gas market interventions internationally. This review highlights differences in the types of interventions used in OECD and non-OECD countries. Their assessment of each country is presented the table below.

Region	Country	Government ownership	Export restrictions	Domestic supply controls	Pricing regulation
Asia					
	China	Yes	No	No	Yes
	India	Yes	No	Yes	Yes
Central & South America					
	Argentina	No	No	Yes	Yes
	Mexico	Yes	No	No	Yes
	Peru	No	Yes	Yes	No
Europe					
	Netherlands	No	No	No	No
	Norway	No	No	No	No
	United Kingdom	No	No	No	No
Middle East & North Africa					
	Algeria	Yes	No	Yes	Yes
	Egypt	Yes	Yes	Yes	Yes
	Oman	Yes	Yes	Yes	Yes
	Qatar	Yes	No	No	Yes
	UAE	Yes	No	No	Yes
North America					
	Canada	No	Yes	No	No
	United States	No	Yes	No	No
South East Asia					
	Indonesia	No	No	Yes	Yes
	Malaysia	Yes	No	No	Yes
	Thailand	No	No	No	Yes

Source: EnergyQuest 2013.
Note: OECD countries are highlighted.

Most of the OECD countries reviewed adopted some form of market approach to determine outcomes in their domestic gas markets and have avoided imposing export controls. Two notable exceptions that have export controls are the United States and Canada.

[1] The netback price is a notional price of gas at a particular point along the gas supply chain. It is calculated by subtracting downstream costs, such as liquefaction and shipping from the delivered price of LNG to the export customer.

The United States and Canada both require that approvals be granted for the export of gas, which are assessed on the basis of a public interest test. In the United States, the export of LNG must be approved by the Federal Government's Department of Energy (DOE). Although there is no binding definition of public interest, DOE guidelines indicate the criteria relate mainly to energy security, domestic gas requirements and the promotion of market competition. The key issue for assessing the public interest is whether or not the proposed export of gas will undermine the provision of competitively priced gas to a minimally regulated market.

Applications for the export of LNG to countries that have a free trade agreement with the United States are automatically deemed to be in the public interest and, thereby, approved by DOE. For the export of LNG to countries without a free trade agreement with the United States, applications for the export of LNG are subject to a public interest review whereby the burden of proof is on showing that the approval of an export licence is not in the public interest. As at early September 2014, DOE had approved nine applications for permits to export LNG to non-free trade countries, and had 22 applications pending for another 21 facilities.

Exports from Canada require approval from the federal energy regulator, the National Energy Board (NEB). The NEB reviews applications to ensure that the amount of gas proposed for export is surplus to the requirements of Canadian users. Providing this is the case, exports are deemed to be in the public interest. As at September 2014, seven export licences for terms of 20 to 25 years have been approved to LNG proponents.

Without exception, all the non-OECD countries reviewed in the EnergyQuest study intervened in setting the price for natural gas. The intervention usually targeted wholesale gas prices through regulation and/or the quantity of gas available for domestic users, and included one or more of the following policy mechanisms:

- majority government ownership of gas supply
- restrictions on the export of gas
- controls on the domestic supply of gas, through measures such as volume reservation and acreage quarantining

A general finding is that while such policy measures may reduce domestic gas prices in the short term, in the longer term they are likely to result in adverse impacts on the broader economy and more specifically on:

- energy and environmental improvements (particularly, energy efficiency)
- foreign investment
- the supply of gas and, hence, put upward pressure on gas prices
- government budgets

Australian domestic gas market interventions

In Australia the Western Australian and Queensland governments have policies for the reservation of gas to supply domestic users. The Commonwealth does not have a domestic gas reservation policy for its offshore resources and no national export controls on LNG.

Western Australia has an 'in principle' domestic gas reservation policy that has been in place since 1979 through State Agreements with the North West Shelf (NWS) LNG project and more recently the Gorgon LNG project. Although not formalised in legislation, a reservation policy was adopted in 2006, which required gas export projects to reserve up to 15 per cent of production for supply to the domestic market as a condition of access to Western Australian land for the location of processing facilities. The reservation percentage target is based on 2006 estimates of future Western Australian domestic gas demand, gas reserves, and LNG production. The target is subject to periodic review. The Western Australian Economic Regulatory Authority recommended this year that the policy be rescinded on the basis that there was no economic justification of government intervention.

Queensland has adopted a 'light-handed' and more adaptive approach - the Prospective Gas Production Land Reserve (PGPLR) policy, which may be applied as a condition for the release of petroleum producing land. The policy allows the Queensland Government to stipulate as a condition of granting a production licence that gas produced from an area is provided only to the domestic market. The rationale for the PGPLR policy is to ensure the growth of the LNG export industry does not create a shortage of supply for large gas users in the domestic market. The PGPLR policy has to date not been applied.

The basic economics of domestic gas reservation

The need for a gas reservation policy is based on the premise that a market failure results from the domestic gas market linking to the export market, insofar as it introduces a distortion to the domestic market that creates an inefficient allocation of resources. Simply put, without a reservation policy the domestic market will not supply sufficient gas at a price that will allow the market to behave efficiently.

As a consequence, a reservation policy is seen as a mechanism to avoid a shortfall in the supply of gas and/or lower the price of gas to domestic users. The objective is to remove the perceived inefficiency by making available cheaper gas than otherwise to users, and thereby benefiting the economy more than if the gas was exported.

This view is not supported by theory. There are two general economic effects arising from the implementation of a domestic gas reservation policy:

- A reduction in economic welfare due to reductions in the economic benefits obtained by gas users or producers that are not offset by gains in other sectors of the economy
- A transfer of income from gas producers to gas consumers. The net benefit from which is dependent on the particular winners and losers from the policy, and the extent that their gains and losses are ultimately accounted for in Australia

While the impact on the efficiency of a reservation policy is unambiguously negative, no general conclusion can be drawn about the combined effect because the second effect will depend on the specific circumstances, particularly where the income flows (profits) accrue.

With respect to the efficiency of a domestic gas reservation policy, there are a few general insights on the impacts on particular economic agents.

Impact on gas users

With the implementation of a domestic gas reservation policy, domestic gas users as a whole obtain an economic benefit from increased gas consumption as a result of the lower price of gas. However, some of the possible negative consequences of sustained lower prices include:

- Industries that benefit from the policy may persist for longer and attract investment away from other industries
- The relatively lower price of gas may inhibit the need for industries to innovate, particularly in the use of other fuels and processes
- If gas users become reliant on a subsidised gas price, it is likely to lead to over consumption and in the longer run and may amplify any inefficiencies in the use of gas or energy more broadly

Impact on gas producers

In short-run, producers are likely to respond to the reservation policy as they would if a tax was introduced, by reducing supply. The profitability of gas producers is reduced either through the redistribution of part of the economic rent of the gas resource to gas users in the form of a subsidy, or lost due to marginal gas projects becoming commercially unviable and no longer contributing to supply.

In the longer run, the lower returns from gas production are reflected through producer investment decisions as well as their operating decisions. As a result, there is a relatively lower level of investment in new supply compared to not having the reservation policy and, therefore total gas production is lower than otherwise. The extent to which producers respond to the policy is dependent on other investment opportunities and the impact of uncertainty about future conditions.

A gas reservation policy is also likely to impact gas producers by increasing supply costs through the need to provide additional infrastructure that would not otherwise have been provided, and an increase in sovereign or policy risk through the government intervention. In addition, any limitation on the ability of producers to fully trade their commitments concerning the reservation of gas is likely to increase costs and the risk premium attached to investment in gas supply. The opportunity for producers to benefit from lobbying activity if negotiation over the application of the policy is possible may also dissipate part of the economic rent available from the gas resource.

Impact on government revenues

If efficient resource royalty arrangements are in place, part of the resource rent from gas production will be captured by government(s). Under a domestic gas reservation policy, some of this rent to government is redistributed to gas users.

General observations

Over recent decades there has been a major trend in developed economies for more efficient policy mechanisms aimed at addressing market failures and, thereby, reducing distortions to firm investment and production decisions. A gas reservation policy is inconsistent with this trend.

It is generally accepted that the higher domestic gas prices from linking to an export market are due to market dynamics and not a market failure. While there would be winners from a reservation policy, the gains to the winners (gas users) are unlikely to offset the direct economic losses to producers, and the broader economic losses that would arise over the longer term.

Quantifying the economic effects of a gas reservation policy requires determining the impact of the policy on the real income accruing to domestic residents and, therefore, the effect on their consumption possibilities, which is a measure of economic welfare.

While some studies have attempted to show the impact of gas exports on domestic industries, the assessment of economic impacts are expressed as changes to gross domestic product, which is a measure of real factor income and not economic welfare. Other studies have attempted to assess the economy-wide impacts of a domestic gas reservation policy, but none have been found to have comprehensively measured the change in real income to domestic gas residents (the extent that profits ultimately reside in Australia needs to be taken into account).

This highlights the need for any assessment of the net benefit of a domestic gas reservation policy to capture the actual value of the policy flowing to directly affected industries and the diffusion of this value through the economy in the form of wages, profits, income to linked industries and tax revenues to governments. To adequately measure the change in real income to domestic residents the ownership share of income transfers between foreign residents and domestic residents needs to be accounted for. There is insufficient detail provided in Australian studies on how the issue of ownership shares has been dealt with.

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APPENDIX A TIMELINE OF KEY GAS DEVELOPMENTS IN AUSTRALIA

Year	Event
1837	A private Act established the Australian Gas Light Company (AGL)
1837	Reticulated town gas first provided in Sydney
1900	First discovery of natural gas at Roma in Queensland
1912	*1912 Gas Act* (NSW)
1935	*Gas and Electricity Act 1935* (NSW)
1961-62	First production of natural gas in Queensland
1965-1968	First gas fields discovered in Perth Basin (Mondara and Dongara)
1966-67	First production of natural gas in Western Australia
1968-69	First production of natural gas in Victoria
1969-70	First production of natural gas in South Australia
1971-1975	Completion of the Parmelia Pipeline, discovery of NWS gas fields, State Energy Commission of Western Australia (SECWA) established
1973	Commonwealth legislation establishes the Pipeline Authority, to create the Moomba (SA) to Sydney pipeline
1976	Moomba to Sydney pipeline completed
1977	Commonwealth Ministerial Statement to the effect that gas exports will be permitted in future once the Government is satisfied that domestic requirements have been considered
1977	Approval for LNG exports from the North West Shelf (NWS) first granted, together with tax concessions
1977-1981	NWS agreements and contracts initiated and signed
1979	*North West Gas Development (Woodside) Agreement Act 1979* (WA) notes that the Commonwealth has approved the sale of up to 6.5 million tonnes per annum of LNG over a term of not less than 20 years
1983-84	First production of natural gas in Northern Territory
1984-1989	Completion of the Dampier to Bunbury Natural Gas Pipeline, Domestic gas from NWS project first produced, first shipment of LNG from WA, Varanus Island domestic gas facility starts production
1985	*Natural Gas (Interim Supply) Act 1985* (SA) reserves gas for domestic consumption
1986	*Gas Act 1986* (NSW), included the Third Party Access Code for Natural Gas Distribution Networks
1988	*Gas Act Amendment Act 1988* (Qld) provides for the Governor in Council to do 'all acts and things necessary' to ensure sufficiency of gas supply

1989-90	First Australian LNG exports (via two LNG trains connected to the North West Shelf Project, WA)
1991	A National Strategy for the Natural Gas Industry
1992	Third LNG train constructed in WA
1992-1996	Establishment of Mondarra Gas Storage facility, second Varanus Island domestic gas facility (East Spar) starts production, SECWA splits into AlintaGas and Western Power, WA third party access framework introduced separating gas purchase and gas shipping, Goldfields Gas Pipeline completed (WA)
1993	Joint Study on the long term supply of natural gas for NSW: Report to the NSW Minister for Energy
1994	COAG agrees to the removal of all remaining legislative and regulatory barriers to the free trade of gas within and across jurisdictional boundaries by 1 July 1996: Agreement to Implement the National Competition Policy and Related Reforms included agreed implementation of the National Framework for Free and Fair Trade in Gas
1996-97	First production of natural gas in NSW , first production of CSG in Queensland
1997	National Third Party Access Code for Natural Gas Pipeline Systems approved by COAG
1997	Gas Pipeline Access Law
1997	Commonwealth control on LNG exports removed
1997-1999	Australian Heads of Governments sign National Gas Pipelines Access Agreement establishing a national framework for access to natural gas pipeline, Independent Gas Pipeline Access regulator established in WA, *Gas Pipelines Access (Western Australia) Act 1998* enacted, AlintaGas privatised (WA)
1999	Victoria establishes the Declared Wholesale Gas Market (DWGM)
2001	NSW Camden coal seam gas production commences
2002	COAG Energy Market Review
2003	Inquiry: Exploring Australia's Future – impediments to increasing investment in minerals and petroleum exploration in Australia [House of Representatives Standing Committee on Industry and Resources]
2003	Ministerial Council on Energy (MCE) report to COAG: Reform of Energy Markets
2003	*Barrow Island Act 2003* (WA), Gorgon LNG project required to supply 2,000 PJ of natural gas for domestic use over the life of the project. Domgas plant with 300 TJ/day capacity to be constructed
2003-2005	Retail Energy Market Company established WA, Economic Regulation Authority established WA, Gas Industry Ombudsman Scheme established WA, Retail Gas Market deregulated WA
2004	Expansion of gas program contained in the MCE 2003 report, Reform of Energy Markets

2004	Australian Energy Market Agreement signed by COAG to establish national energy market institutions
2004	Fourth LNG train constructed at NWS project in WA
2005	Gas Market Leaders Group established by the MCE to develop actions to address market issues
2005-06	LNG first exported from NT (3.7 Mtpa)
2006	Policy on Securing Domestic Gas Supplies (WA)
2006-2009	Two gas supply disruptions in WA, 175 tonne/day LNG facility commissioned for domestic market in WA, *Gas Supply (Gas Quality Specifications) Act 2009* enacted (WA)
2008	Gas Bulletin Board established for the eastern market
2008	National Gas Law and National Gas Rules enacted (replaces the Gas Access Code)
2008	Fifth LNG train constructed in WA
2009	Queensland releases its Blueprint for Queensland's LNG Industry, which flagged the possibility of a domestic gas reservation policy
2009	Queensland releases a consultation paper: Domestic Gas Market Security of Supply
2009	Queensland adopts its Prospective Gas Production Land Reserve (PGPLR) policy
2010	Gas Short-Term Trading Markets established in NSW and SA
2010-2011	WA Parliamentary Inquiry into domestic gas prices, Independent Market Operator becomes operator of new Gas Bulletin Board and responsible for Gas Statement of Opportunities (WA), Devil Creek domestic gas facility starts production (WA)
2011	*Gas Security Amendment Act 2011* (Qld) implements the PGPLR policy
2011	Inquiry into domestic gas prices [WA Legislative Assembly Economics and Industry Committee]
2011	Gas Short-Term Trading Market established in Queensland
2012	Gas Market Development Plan [Standing Council on Energy and Resources]
2012	Coal seam gas inquiry [NSW Legislative Council General Purpose Standing Committee No. 5]
2012	Inquiry into the economics of energy generation [NSW Legislative Assembly Public Accounts Committee]
2012	Pluto LNG project – first LNG project subject to 2006 WA Domgas Policy, 15% of LNG production to be supplied to domestic market within 5 years of LNG exports commencing or after 30 million tonnes of LNG have been shipped (4.3 Mtpa)
2012	*Gas Services Information Act 2012* enacted (WA)
2012	Prelude FLNG Project approved in WA (world's first floating LNG)

2013	*Natural Gas (Canning Basin Joint Venture) Agreement Act 2013* (WA) provides that if commercially viable gas is discovered by mid-2016, the parties must submit a plan for construction of the domestic gas project
2013	Inquiry into Downstream gas supply and availability in NSW begins [NSW Legislative Assembly State and Regional Development Committee]
2013	Inquiry into the economic implications of floating liquefied natural gas operations begins [WA Legislative Assembly Economics and Industry Standing Committee]
2013	Inquiry into the implications for Western Australia of hydraulic fracturing for unconventional gas begins [WA Legislative Council Environment and Public Affairs Committee]
2013	Inquiry into key challenges and opportunities begins [NT Legislative Assembly Committee on the Northern Territory's Energy Future]
2014	Train 1 of Queensland Curtis LNG due for completion (3.9 Mtpa capacity)
2014	Completion of a gas supply hub at Wallumbilla, Queensland

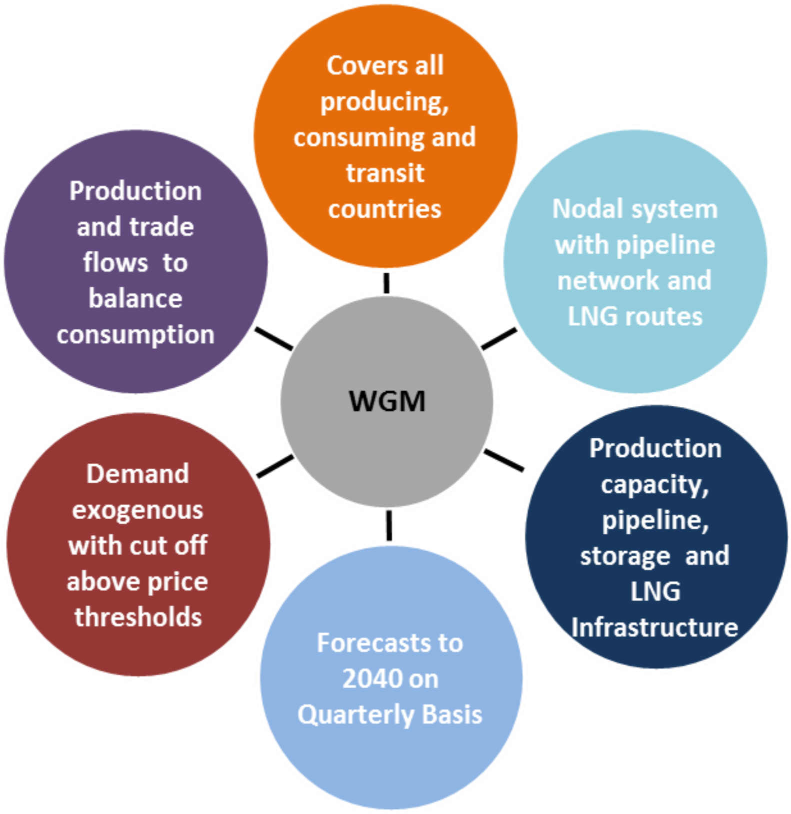
Source: Adapted from Haylen, A. and Montoya, D. (2013). *Gas: resources, industry structure and domestic reservation policies*. NSW Parliamentary Research Service, Briefing Paper no. 12/2013: pp.42-44; Independent Market Operator (2013). *Gas Statement of Opportunities*: pp. 27-28.

APPENDIX B NEXANT WORLD GAS MODEL

The World Gas Model (WGM) has been developed by Nexant's Global Gas practice. Figure B1 presents the main system features of the model.

The model considers every country in the world which either consumes or produces natural gas. Large countries including the US, Canada, Russia, China, India, Australia, Malaysia and Indonesia are further segmented by region. The focus is on the growing international trade of natural gas by cross-border pipeline and as LNG. The model currently includes over 130 countries with space to add new countries as needed.In addition to the information for infrastructure and supply, the database also cover cost for all facilities in the model including production, pipelines, liquefaction and regasification terminals, storage facilities and LNG shipping. Capital costs for production and infrastructure are represented as unit costs (per mmbtu or per thousand cubic metres) on a Long Run Marginal Cost (LRMC) basis. Shipping costs are built up from shipping distances and assumed day rates and fuel costs.

Figure B1: System of the WGM



The WGM projects global, regional and national gas supply and demand balances, international gas trade by pipeline and LNG and both contracted and spot prices. The least cost optimisation of LNG trades is determined by the unit costs of production, liquefaction, shipping and regasification (and pipeline transportation in the case of pipeline trades). Spot prices are estimated with reference to cost of supply, competing fuel prices and the "tightness" of the market. The projected LNG demand covers the contracted and un-contracted LNG. The un-contracted LNG includes portfolio contracts i.e. the contract may specify the export node but not the import node; or the contract may specify the import node but not export node.

The model is built based on assumptions including key assumption for gas supply (figure B2) and key assumption for infrastructure (figure B3).

Figure B2: Key Assumptions – Gas Supply

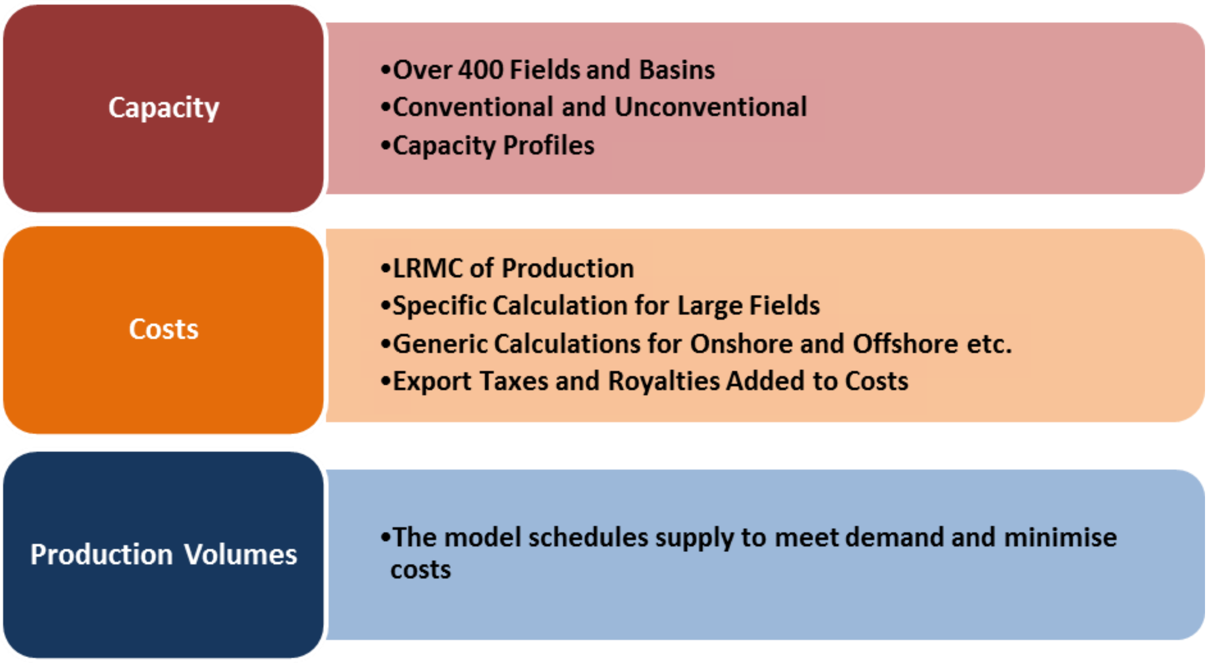


Figure B3: Key Assumptions – Infrastructure