The Economic Impact of LNG Exports on Manufacturing and The Economy

– How should we respond to the looming crisis?

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The Australian Workers' Union

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Key Points

Australia's east coast gas markets urgently need a domestic gas reservation policy to avoid the decimation of key manufacturing industries. The imminent start of production and exporting from three huge LNG plants in Queensland will lead to a near tripling in domestic gas prices throughout the interconnected eastern gas markets, as producers divert gas volumes to higher priced exports at the expense of local users. Domestic gas prices in Western Australia are also expected to rise significantly over the next decade.

While there will be positive economic affects from increased LNG exports these will be outweighed by the negative impacts – particularly on the manufacturing sector – arising from the jump in gas prices and the potential supply shortages in the east coast markets:

- A significant loss in the value of manufacturing input, ranging from -$14.2 billion (equal to -3.9% of output) to -$59.3 billion (-15.4% of output), with associated job losses in the manufacturing sector of between 21,900 and 91,300.
- Economy-wide net losses of between $26.6 billion to $110 billion of the value of output, and associated job losses of between 56,500 and 235,800, once you add the net indirect flow-on effects of the suppliers to the manufacturing and LNG sectors. The overall job losses equate to between -0.5% and -1.8% fewer jobs (than the base case), while GDP is between -0.9% to -2.2% lower.
- Negative impacts on households with annual gas bills rising $260 (26 per cent) over the next four years.
- Higher greenhouse gas emissions in Australia as there is a switch to coal-fired electricity generation and away from domestic gas usage.
- A marked rise in the current account deficit due to rising profit repatriation from the (majority) foreign owned LNG producers, while net exports will deteriorate with the decline of manufacturing production.

The bottom line is that, in effect, there will be a substantial transfer of national income from Australian gas-using industries, particularly manufacturing, and households to the gas and LNG producers.

Background to Increased Prices

Australian gas markets are currently undergoing a significant period of change. Historically the domestic gas markets have been dominated by long term bilateral contracts between suppliers and consumers, which have underpinned investment in infrastructure, kept domestic gas prices low and provided a competitive advantage to our domestic industry. However, as major LNG export projects come on line in Queensland, the demand for gas will increase dramatically. Despite these LNG projects being accompanied by significant investment in increasing the supply of gas, there is an increasing likelihood that serious supply constraints will emerge as gas is redirected from domestic markets to satisfy export demand. Consequently, as domestic markets are increasingly linked to higher priced international markets there will be significant upwards pressure on domestic gas prices and as long term bilateral contracts begin to expire Australian gas users will face a much higher price of gas.

The era of cheap and abundant supplies of gas for Australia's domestic users is over. Historical gas prices of around $3-4/GJ are set to at least double or triple within two to three years, due to the huge demand for gas for export, via a raft of LNG developments in Western

Australia, the Northern Territory and Queensland. With export prices close to $12/GJ (ex port), gas producers are expected to divert supply to the LNG plants as 5 major plants (3 in Queensland) progressively come onstream over the next two years.

Domestic supply is not an issue in Western Australia thanks to that state's domestic gas reservation policy (although prices will rise). But in the eastern states' market – which is mostly interconnected by an extensive pipeline network – the lack of a gas reservation policy for domestic users is not only leading to higher prices, but also potential supply shortages as gas producers chase higher export returns while supply increases at a slower rate than previously expected.

Net Negative Impacts on the Economy

While the Australian economy will derive positive benefits from higher LNG export revenues, these will be outweighed by much larger losses to production and national income because of the substantial negative impacts on Australian manufacturing, in particular, and other associated industries, resulting from higher prices and supply shortages. There will also be significant employment losses in the affected industries, but few permanent jobs created by ongoing LNG production.

In effect, this will see a substantial transfer of national income from Australian gas-using industries to the gas and LNG producers. However, as there is a high level of foreign ownership in these sectors, a significant portion of the higher profits will leak overseas as repatriated profits and dividends. We estimate that repatriated profits and dividends will rise from around $7.2billion now to $26.6billion by 2023 (with the Queensland share at $7.6billion in 2023). The loss of manufacturing production will also see a marked rise in imports and lower manufacturing exports, with the worsening trade deficit adding to the higher repatriated profits and causing a sharp deterioration in the Current Account Deficit.

Meanwhile, households are also negatively impacted with the annual gas bill expected to rise by $260 (26 per cent) over the next four years, although this rise could be conservative. This effectively represents a transfer from households to the gas producers and exporters of over $2 billion.

Potential Supply Shortfalls

However, even with a strong ramp up in gas production there still exists a potential shortfall in supply, which is expected to rise steadily over the forecast horizon. This shortfall is despite a projected fall in domestic gas demand and can be attributed to the surge in demand from LNG export terminals. These projects have already locked in supply contracts with their overseas customers and if they are unable to achieve the projected production levels from the wells linked to the terminals they will turn to domestic market supplies to fulfil their obligations, creating production shortfalls and supply constraints. This is particularly true of producers who are active in both the domestic and international markets, such as Santos and Origin. Therefore these constraints are primarily a result of policy failure on the demand side by allowing LNG export demand to expand so significantly and rapidly and outstrip production capabilities with little regard for the needs of the domestic market.

Manufacturing to suffer the largest negative impacts

The industries which will suffer the largest negative impacts from either (or both) higher gas prices or gas shortages will be those industries which have two or more of these characteristics:

- Higher ratios of gas use intensity per unit of production, usually meaning they will incur higher costs

- Higher levels of trade exposure, with those industries which are more highly exposed to international competition less able to pass on higher costs
- The industry relies critically on gas as a feedstock or critical input into its industrial processes, such as alumina refining, fertilizer production and a range of basic chemical products.
- The inability to switch from gas as an energy source (either in use in generating steam or for drying, or for onsite electricity generation) to other sources, such as coal-fired electricity generation (either on-site or via the grid).

Manufacturing in general, and the sub-sectors of basic non-ferrous metals (mainly alumina production, in terms of high gas intensity), non-metallic mineral products (especially ceramics, such as bricks and tiles; glass and cement), petroleum, chemical, polymer and rubber manufacturing, iron and steel and parts of pulp and paper manufacturing are among the sectors with both high gas intensity and high trade exposure, which will suffer the largest impacts.

To analyse the impacts of the jump in gas prices and potential supply shortfalls (the latter mainly in east coast markets), we investigated two scenarios:

- A 'worst case' scenario where all of the substantial shortfall in gas supply projected in 2023 is concentrated in the manufacturing sector, based on the assumption that gas for the 'mass market' (mainly for the residential sector) and the GPG sector will be provided as demanded.
- A 'short term price hike' scenario related to the near tripling in prices by 2016. We assumed that the most vulnerable ports of manufacturing shut-down (some permanently), which reduces output and employment.

The 73.5 PJ shortfall projected by AEMO for the east coast market in 2023 represents 15.4% of the expected base case consumption of the manufacturing sector in Australia. Our simple assumption is that manufacturing production will be reduced by this proportion in 2023. In terms of direct effects on the gross value of manufacturing production (which is roughly equivalent to the value of sales), this represents a direct loss of $59,278m (in constant 2011/12 prices) compared to the base case. In terms of employment, the direct impact on manufacturing employment is 91,300 fewer jobs.

It is important to note here that this simple analysis and the direct impacts above represent a 'worst case' outcome, or an 'upper limit' for the direct adverse outcomes. It implicitly assumes that steps are not (or are unable to be) taken to mitigate the shortage of gas supply, such as switching from gas to coal-fired electricity, or even on a broader basis, new (extra) gas supply does not come onstream despite the likely higher prices associated with the shortages.

The net direct impact on industry output is negative $58,472 million, after adding the positive benefits to LNG output from 73.5 PJ of gas. The total net loss of industry output, after accounting for the flow-on multiplier effects on industry, is negative $110,156 million. In terms of the base case GDP forecasts, this represents a reduction in GDP of -2.2 per cent.

In terms of the 2016 price spike scenario, while users on long term contracts (i.e. beyond 2017) will be shielded when prices jump to between $8 to $9.5 per GJ, the uncontracted portion (assume to be around 25% of users) will be exposed to the sharp rise in prices. We have assumed that around 20 per cent of the uncontracted, high gas intensity manufacturers exposed to the much higher prices will be rendered uneconomic, and will choose to shutdown. Some of these shutdowns will be permanent. This equates to around 3.9% of gas demand from the manufacturing sector, with an equivalent impact assumed for overall manufacturing output.

Table I: Industry Output Impacts: 2023 Supply Shortfall

	LNG: Export Value of 73.5 PJ		Manufacturing: 73.5 PJ gas supply shortage		Net Impacts on Gross Output	Net Impacts on Economy: GDP	as % of Base Case GDP	Net Employment Impacts
	Output value	% impact	Output value	% impact	Output value	Gross Value Added		
	$m (2011/12 prices)		$m (2011/12 prices)		$m (2011/12 p)	$m (2011/12 prices)		('000)
Direct Impacts	806	4.1% (a)	-59278	-15.4%	-58472	-16277	-0.8%	-91.3
Indirect Industry Output Impacts	185		-51868		-51684	-29491		-144.6
Total Industry Output Impacts	991		-111146		-110156	-45768	-2.2%	-235.8

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

(a) Proportion of expected Queensland LNG production in 2023

Table II: Industry Output Impacts: 2016 Price Spike

	LNG: Export Value of 3.1 PJ		Manufacturing Impacts		Net Impacts on Gross Output	Net Impacts on Economy: GDP	as % of Base Case GDP	Net Employment Impacts
	Output value	% impact	Output value	% impact	Output value	Gross Value Added		
	$m (2011/12 prices)		$m (2011/12 prices)		$m (2011/12 pric	$m (2011/12 prices)		('000)
Direct Impacts	34	0.2% (a)	-14203	-3.9%	-14170	-4021	-0.2%	-21.9
Indirect Industry Output Impacts	8		-12428		-12420	-11687		-34.7
Total Industry Output Impacts	41		-26631		-26589	-15707	-0.9%	-56.5

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

(a) Shortfall of 3.1 PJ in 2016 as a proportion of expected Queensland LNG production in 2016/17

The direct impact on the value of manufacturing output will be negative $14,203 million. The total net loss of industry output, after accounting for the flow-on multiplier effects on industry, is negative $26,589 million. Note we have only assumed a small positive impact for LNG compared to the base case (based on the expected gas shortfall quantum), as our base case assumed full capacity export and revenue from the Queensland LNG plants.

It is important to note that the above are impacts on production. They do not take account of the deferral or outright cancellation of potential investment projects due to the prospect of significant price rises or potential supply shortages. And in terms of the 2016 price spike scenario or the "worst case" 2023 supply shortfall, it is important to remember that once domestic manufacturing capacity shuts down or is moved offshore, it is unlikely that it will return home or be re-started.

Over the past two years, three other reports have been produced which have attempted to measure the impact of rising gas prices and potential supply shortages on the manufacturing sector and the overall economy – from Deloitte Access Economics, Manufacturing Australia and the National Institute of Economic and Industry Research. Although the estimates of the impacts of different scenarios and assumptions across the three studies and BIS Shrapnel's study (this study) vary, the bottom line conclusion is that the economy in net terms is negatively impacted by the expansion of LNG exports and the resulting consequences of significantly higher gas prices and supply constraints. All the studies show manufacturing will suffer the largest negative effects.

Policies Overseas and in Australia

Both the USA and Canada have 'national interest tests' that are applied to any application for a natural gas export license. These policies can act as a de facto reservation policy by allowing their respective governments to limit export volumes and ensure that domestic demand for natural gas is met. In Australia there is no national domestic gas reservation policy, however

Western Australia does have a policy that reserves 15% of production from LNG export projects for domestic consumption. Despite these respective policy stances, the LNG export industries across these jurisdictions have experienced significant investment in recent years.

In contrast, the east coast of Australia has no enforced reservation policy and as a result is facing the prospect of supply shortages as LNG export facilities come on line and ramp up to full capacity. Any production shortfalls will likely result in reduced supply for the domestic market as exporters look to fulfil their obligations by sourcing gas from the domestic market. Without a reservation or national interest policy, there will be no means with which to prevent this and the burden will fall on the Australian consumer and industry base.

The genesis of the looming crisis in gas prices and supply lay in the original decision to approve three huge LNG developments in Gladstone, Queensland, all based on coal seam gas (CSG) extraction – an industry arguably still in its infancy in Australia – and all to be developed virtually simultaneously and come onstream within a year of each other. Given the substantial amount of gas wells to be developed within a relatively short space of time and potential technical difficulties, it should have been apparent that enough supply for the plants could be an issue.

These issues and the potential impacts of not ensuring there would be sufficient, reasonably priced gas available for domestic markets represents a serious policy failure. It is apparent that the assessment process and economic evaluation – in terms of the national interest – for the Queensland LNG plants was deficient, both by the State and Commonwealth Governments. It would have been prudent to approve only one or two CSG-based LNG projects, and allow subsequent CSG LNG plants only after a proper assessment. The current ambitious plan to speed up the approval and development of more CSG wells and lift production in NSW and Victoria is not the answer. Without a domestic gas reservation or equivalent policy, there is still no guarantee that the increased CSG production will not be diverted to the Queensland LNG plants, via the existing pipeline network and a (new) short extension to Queensland from NSW.

The end of the era of low gas prices means the substantial erosion of one of Australia's key comparative advantages – cheap energy - which has underpinned the development of energy-intensive minerals processing, building materials and chemical industries. Unfortunately, this will coincide with the demise of Australian car manufacturing and potentially much of the country's defence-related manufacturing capabilities as the next round of submarines and warships are sourced from overseas. This makes the case for urgent action more acute.

With the impacts outlined above we feel that allowing the unfettered export of LNG will be a net negative for the Australian economy and that there should be a policy response to ensure that the benefits of our natural gas reserves are best shared across the nation. In considering both a national interest test for export licenses and a domestic gas reservation policy we feel that a reservation policy would be most effective in maintaining affordable gas domestically, supporting domestic industry and encouraging investment in the oil and gas sectors.

The WA reservation policy is based on forecasts for domestic gas demand that were made in 2006 and it is due to be reviewed in 2014/15. A similar method could be used to determine the proportion of gas to be reserved for domestic use across the west and eastern markets. Based off the projections for demand (both for domestic use and LNG) included in the 2013 Gas Statement of Opportunities for eastern and south-eastern Australia, domestic demand in these markets is expected to account for close to 30% of total production by 2023. In Western Australia, this proportion is much lower at approximately 10%. Nationally (excluding the Northern Territory) domestic demand makes up 15% of total demand, however in order to reduce pressure on prices a moderately higher proportion around 20% would be advisable to provide some slack in the market.

Impact of a Gas Reservation on Gas Producers' Profits

What would be the impact on gas producers' profits with a 20% reservation in the East Coast markets? If the east coast markets had such a policy in the first place (as there should have been) when the three large CSG LNG projects were approved initially, we estimate the gas producers overall margin (weighted average for LNG exports and domestic gas sales) would be cut from 45% to 40% in 2017/18, when the three CSG LNG plants currently under construction hit full capacity of 25.7Mt. This assumes the margin on domestic gas is 15% and the margin on LNG is 45% (which is at the bottom of the range of current reported margins on LNG in Australia). At a margin of 45%, this delivers an estimated profit of $7.8 billion for the LNG. At a reservation of 20% of the total production of the three plants, the lower domestic gas price would deliver a profit of around $300 million, with the overall profit $8.1 billion. This would be $1.27billion or 14% less than the $9.4billion if all the gas was sold on the LNG market. Of course these estimates are sensitive to the profit margin assumptions.

We should also highlight the effect of the exercise of market power by gas producers in just the domestic market for gas producers' profits. At the average price of $9.31/GJ assumed for the east coast markets in 2016 – which is the peak in prices because of the exercise of market power – the average gross margin will be 40% to 50%, based on the average costs of production and transportation used in this study. By 2023, under the assumption of increasing supply (and weak demand), the average east coast market price eases to $7.72, but the gross margin on domestic gas sales is still a healthy 25% to 39%.

The above margins compare favourably to the overall gross margin for all reported industries of 12.7%, total Mining of 40%, all industries excluding mining the margin is around 10%, while for the Manufacturing sector the margin is only 7.8%.The upshot is that if one assumed the 20% gas reservation would lead to sufficient domestic supply, and therefore less ability to exercise market power, then domestic prices and gas producers' margins would also be lower, but even assuming a 15% margin, they would still be higher than most other industries.

Nevertheless, with such high profit margins, one could make the argument they can afford a modest cut in profits in order to support Australian industry and help lower greenhouse gas emissions.

1. INTRODUCTION

Australian gas markets are currently undergoing a significant period of change. Historically the domestic gas markets have been dominated by long term bilateral contracts between suppliers and consumers, which have underpinned investment in infrastructure, kept domestic gas prices low and provided a competitive advantage to our domestic industry. However, as major LNG export projects come on line in Queensland, the demand for gas will increase dramatically. Despite these LNG projects being accompanied by significant investment in increasing the supply of gas, there is an increasing likelihood that serious supply constraints will emerge as gas is redirected from domestic markets to satisfy export demand. Consequently as domestic markets are increasingly linked to higher priced international markets there will be significant upwards pressure on domestic gas prices and as long term bilateral contracts begin to expire Australian gas users will face a much higher price of gas.

Although liquefied natural gas (LNG) investment and exports will provide a boost to the Australian economy the rise in gas prices will also result in an increased cost base for Australian industry. This will be felt most keenly in the manufacturing sector where gas can be a significant input. This will result in significant losses across those industries that are unable to switch to alternative fuels or technologies or to pass on increased costs, and will lead to reduced output and employment. There will also be other negative impacts felt across the Australian economy, such as cost of living increases and an increased environmental impact.

1.1 Scope

In response to this, BIS Shrapnel has been engaged by the Australian Workers' Union to provide a paper exploring the impacts of a rise in the price of gas on the Australian economy, with a specific focus on the manufacturing sector.

The scope of our analysis comprises four key components:

1. To present the demand and supply outlook for gas and the corresponding price forecasts
2. Utilise these price forecasts to investigate the impact on employment and output in the manufacturing sector, plus any related macroeconomic impacts and non-economic considerations
3. Investigate the impact of price rises on retail consumer prices and the impact on household budgets
4. Use the USA and Canadian gas markets and their respective policy settings as case studies with which to compare Australia's current policy settings and options

With a significant amount of research having already been performed in this field, this paper will not provide its own price forecasts. Instead we will select existing price forecasts that we feel are most appropriate and provide our assessment of the impact such price paths will have on the Australian economy and manufacturing industry.

Due to the significant differences between them, the east and west coast Australian gas markets will be treated separately. With the east coast markets only now being exposed to international markets thanks to LNG investment in Queensland, there will be a greater focus on these markets and their adjustment. The Western Australian experience will be used more as an investigation into its domestic gas reservation policy and the impact of this policy on the local gas industry and the wider economy.

2. AUSTRALIAN GAS MARKETS ARE CHANGING

This section explores the changes occurring across the east and west coast Australian gas markets that are impacting on the outlook for supply and demand.

2.1 East Coast market

2.1.1 LNG expansion

The East Coast gas market has historically been a purely domestic one, with the New South Wales, Victorian, Queensland and South Australian markets all being separate but interlinked. Significant proven and probable (2P) reserves exist across Eastern Australia, with the Gippsland, Otway, Bass and Cooper-Eromanga basins traditionally supplying the majority of the market. More recently investment in accessing CSG reserves has seen the Bowen and Surat basins make up a much larger proportion of Eastern Australian reserves. These reserves are more than sufficient to supply the domestic market into the foreseeable future and this abundant supply, along with the structure of the market, has meant that the eastern market has benefited from low gas prices relative to international prices, which has in turn supported the use of gas by household consumers, electricity generators and the manufacturing industry.

Strong growth in the global demand for gas – particularly from Asia – has underpinned significant investment in coal seam gas (CSG) extraction and LNG export facilities in Queensland. As these facilities come on line in coming years gas exports will increase dramatically and the East Coast gas markets will become linked to international markets and their higher prices. Table 2.1 outlines the committed and the proposed LNG developments, which amount to an enormous increment to gas demand across Australia. Whilst it is unlikely that all the possible projects outlined below will go ahead, even the 3 committed projects will outweigh the current levels of gas demand domestically.

Table 2.1: Queensland LNG developments

Project	Sponsor	Capacity (Mtpa)	Est. consumption p.a. (PJ)	LNG Trains	Cost (A$b)	First exports
Committed						
Australia Pacific LNG	Origin Energy (37.5%)/ConocoPhillips (37.5%)/Sinopec (25%)	9	540	2	25	2015
Curtis Island LNG	CNOOC (25%)/BG Group (73.75%)/Tokyo Gas (1.25%)	8.5	510	2	20	2015
Gladstone LNG	Santos (30%)/Petronas (27.5%)/Total (27.5%)/Kogas (15%)	7.8	468	2	18	2015
Total Committed		**25.3**	**1518**	**6**	**63**	-
Possible						
Curtis Island LNG exp.	CNOOC (25%)/BG Group (73.75%)/Tokyo Gas (1.25%)	3.5	210	1	8	2020
Gladstone LNG exp.	Santos (30%)/Petronas (27.5%)/Total (27.5%)/Kogas (15%)	7.8	468	2	16	2024
Australia Pacific LNG exp.	Origin Energy (37.5%)/ConocoPhillips (37.5%)/Sinopec (25%)	8	480	2	16	2025
Arrow LNG	Shell (50%)/PetroChina (50%)	8	480	2	-	-
Total Possible		**27.3**	**1638**	**7**	**40**	-
Committed + Possible		**52.6**	**3156**	**13**	**102.5**	-

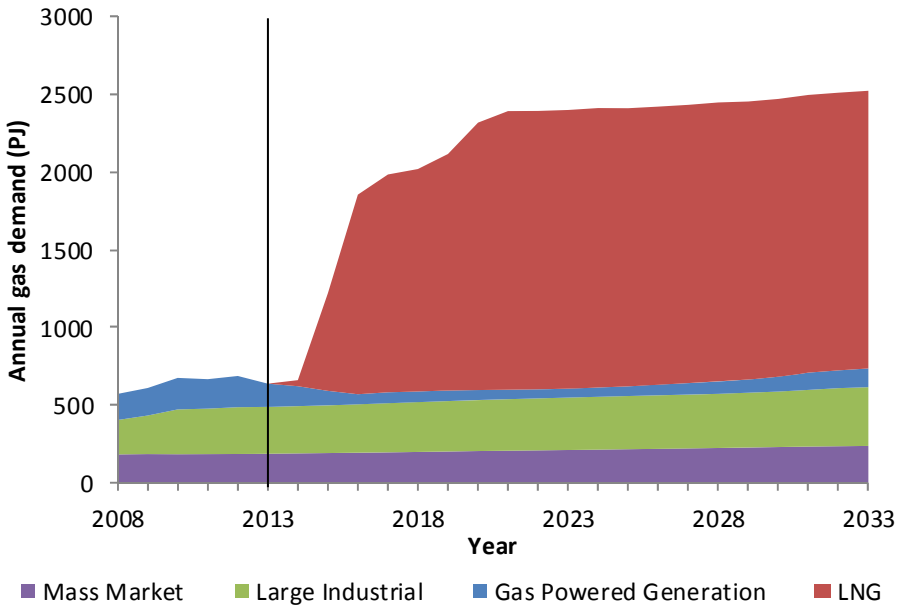
Source: IES Study on the Australian Domestic Gas Market, Eastern Australian Domestic Gas Study, BIS Shrapnel

2.1.2 Emerging supply constraints – creating uncertainty for domestic consumers

Although the demand for gas will surge as these LNG export facilities come on line they have been accompanied by significant investment in gas production. CSG production in the Bowen and Surat Basins is ramping up and is set to supply much of the increased demand for LNG exports. However, with the LNG export facilities having already committed to supply contracts with their overseas customers there is growing concern that delays or weaker than expected production from the new CSG wells will create undersupplies in the eastern gas markets.

Chart 2.1 presents the outlook for natural gas demand across the east coast of Australia, incorporating domestic demand forecasts from the 2013 Gas Statement of Opportunities[1] (GSOO) with updated forecasts for LNG demand calculated by Jacobs SKM for the Australian Energy Market Operator (AEMO)[2]. We have used what we feel is a conservative approach and assumed that only 7 LNG trains are brought on line by 2023. This sees annual LNG export demand ramp up to 1,790 PJ by 2021, compared to a forecast domestic demand of only 600 PJ. So by these estimates Australia is set to export nearly three times the natural gas that it consumes domestically, with the potential for exports to be much higher if more LNG trains are brought online.

Chart 2.1: Projected domestic and LNG demand for the East Coast



note: These projections assume a 7 LNG train scenario

Source: AEMO, SKM

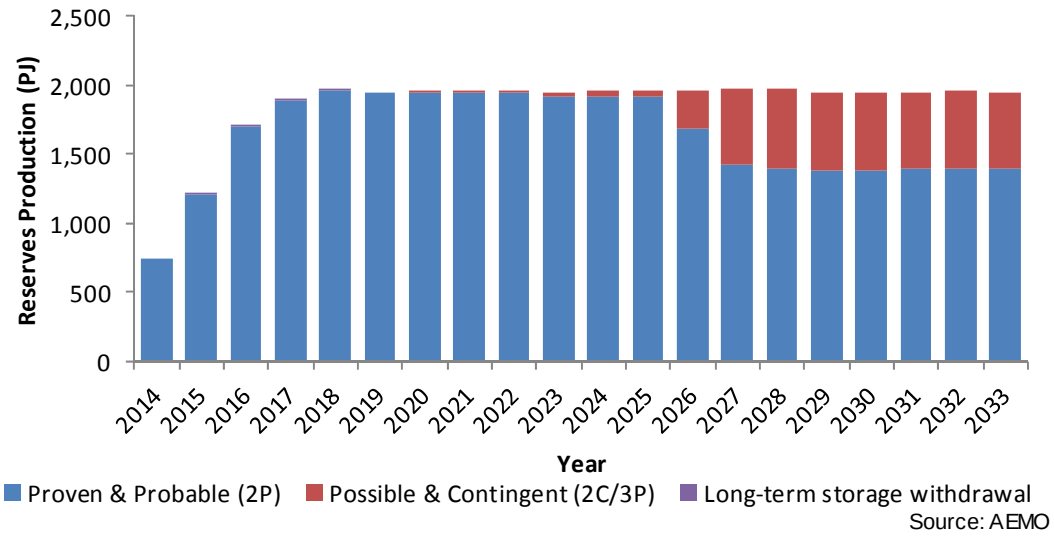
This rapid increase in demand is creating significant uncertainty within the market as supply struggles to keep pace. Anecdotal evidence suggests that some exporters are sourcing gas from the domestic market to insure against any shortfall in production and this is creating tightness in the current market. Ai Group surveyed business gas users and found that over 50% could either not get a serious contract offer or could only get an offer from one supplier[3]. Respondents also noted that prices in new contracts were much higher than historically, particularly for longer term (over two years or beyond 2013) contracts. This highlights reluctance from producers to lock in supply agreements at current prices and suggests an expectation of future supply constraints and price rises.

This expectation is supported by the AEMO's 2013 Gas Statement of Opportunities, with chart 2.2 presenting the production profile of existing and committed projects. When coupled with the projected east coast demand in chart 2.1, a shortfall in gas supply is evident (chart 2.3). Shortfalls are estimated to increase significantly from 2018 and 2019 when the major LNG projects ramp up and begin to reach full capacity.

[1] (AEMO, 2013)
[2] (Jacobs SKM, 2014)
[3] (The Australian Industry Group, 2013, p. 11)

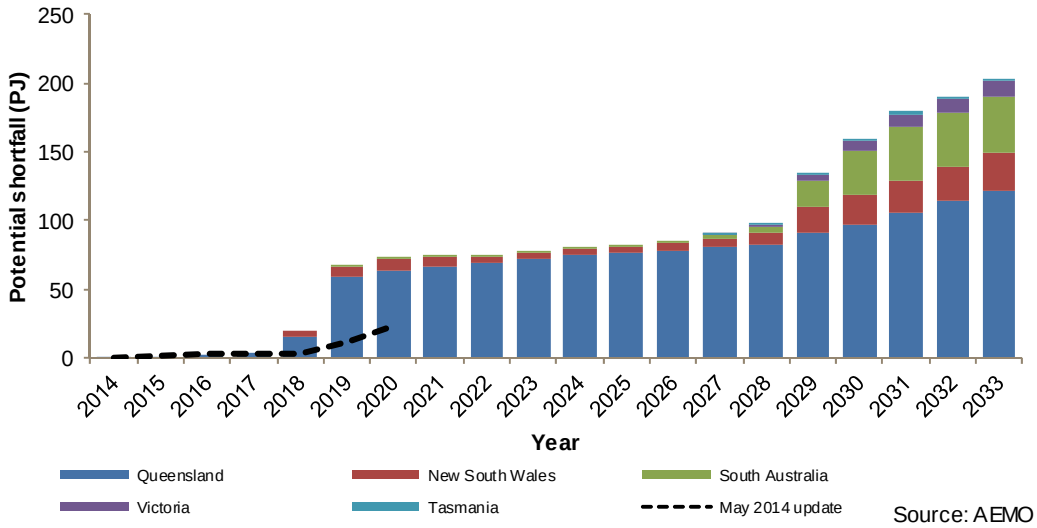
Core Energy estimated that 2P natural gas reserves as at the end of 2012 totalled 53,229 PJ[4]. It also estimated possible and contingent (3P2C) resources of 78,986 PJ and prospective resources of 343,140 PJ, which highlights the abundance of natural gas reserves in Eastern Australia. Using AEMO's current production and demand profiles, Eastern Australia should have sufficient reserves to satisfy demand for the next 20-25 years at least and this ignores the potential for further development of 3P2C and prospective resources or technological advancements increasing available gas resources.

Chart 2.2: Production profile - existing and committed projects



Source: AEMO

Chart 2.3: Annual potential shortfalls



Source: AEMO

However, even with a strong ramp up in production there still exists a potential shortfall in supply, which is expected to rise steadily over the forecast horizon (chart 2.3). This shortfall is despite a projected fall in domestic gas demand and can be attributed to the surge in demand from LNG export terminals. These projects have already locked in supply contracts with their overseas customers and if they are unable to achieve the projected production levels from the wells linked to the terminals they will turn to domestic market supplies to fulfil their obligations, creating production shortfalls and supply constraints. This is particularly true of producers who

[4] (Core Energy Group, 2013, p. 9)

are active in both the domestic and international markets, such as Santos and Origin. Therefore these constraints are primarily a result of policy failure on the demand side by allowing LNG export demand to expand so significantly and rapidly and outstrip production capabilities with little regard for the needs of the domestic market.

Chart 2.3 also includes the updated shortfall included in the May 2014 update. This update only goes to 2020 and provides less detail hence it is only included alongside the more detailed 2013 GSOO shortfall. The lower shortfall primarily reflects a new five year supply agreement between Origin & GLNG, which replaces 55 TJ/day of gas in Queensland which was drawn from other sources in the 2013 GSOO. It also reflects increased supply in NSW as the Santos Narrabri gas project is now included in the projections. However the shortfall still begins to rise in 2019 and 2020 and is expected to move back towards the profile in the 2013 GSOO over the longer term.

2.1.3 Expiring long term bilateral contracts

Traditionally the Eastern Australian gas market has relied on long term bilateral contracts which have provided certainty to both suppliers and consumers and helped underpin new investment. However a significant proportion of these contracts are either expiring or approaching expiry in coming years, with Ai Group's survey of business gas users finding that most respondents' contracts are due to expire by the end of 2015[5], whilst SKM and Energy Quest modelling suggests that the majority of the long term bilateral contracts will have expired by 2018[6] and 2019[7] respectively. These contracts will help shield consumers from rising gas prices initially, but once they expire businesses will likely be forced to recontract at higher prices and under far less attractive conditions.

2.1.4 Impact of wholesale trading hubs

A positive development in the eastern gas markets has been the recent beginning of operations at the Wallumbilla Gas Supply Hub. Whilst wholesale gas markets previously existed in the form of the Victoria Declared Wholesale Gas Market and the Short Term Trading Markets (STTMs) of Adelaide, Sydney and Brisbane, the Wallumbilla Hub should serve to improve liquidity, develop secondary markets and increase information transparency to support more efficient market outcomes and may help ease short term price pressures in these markets. However, with the hub only commencing operations in March 2014 it is still young and its impact remains uncertain.

2.2 West Coast market

The Western market has been exposed to international markets since 1989 when LNG exports began from the North West Shelf (NWS). However, domestic gas prices have been contained thanks to the policy stance of successive Western Australian Governments. Various domestic supply arrangements since the 1970s ensured the Western Australian market had access to an ample and cheap supply of gas and provided certainty to underpin significant investment in increased capacity, and associated industry.

The policy stance has evolved over time but in 2012 the Government clarified its current arrangements in its Strategic Energy Initiative's Energy 2031 paper. Gas producers must

[5] (The Australian Industry Group, 2013)
[6] (SKM, 2013, p. 28)
[7] (BREE, 2013)

demonstrate their ability to meet the Domestic Gas Policy as a condition of project approval. This requires them to[8]:

- Reserve domestic gas equivalent to 15% of LNG production from each export project. This includes developing the required infrastructure and marketing the gas domestically in good faith
- Be subject to independent review
- Commence the provision of gas domestically at the same time as LNG exports
- Provide gas at prices determined by the market

The Government aims to apply the policy in a flexible manner and most arrangements are negotiated on a case by case basis so as to encourage development of gas resources for export whilst also providing supply to the domestic market. The policy will be reviewed in 2014/15.

2.2.1 Expiring long term bilateral contracts

Despite this reservation policy, the Western Australian market does face similar pressures to the eastern market. Many long term contracts are expiring and by 2020 the last of the existing NWS domestic supply contracts will have expired[9]. New contracts are being negotiated at much higher oil linked netback prices[10], which will increase pressure on many of the gas-intensive industries operating in the state.

Although the expiry of these bilateral contracts are troublesome, more concerning is the looming expiry of the North West Shelf (NWS) joint venture's commitment to supply the domestic market with 5,064 PJ of gas. The NWS JV supplies a significant proportion of WA's domestic gas, estimated at 42% for 2014[11], but it is currently unknown whether the NWS will recontract with the domestic market. This creates a significant degree of uncertainty in the domestic market. Statements by the Woodside Energy CEO suggest that the NWS would be willing to continue to supply the domestic market, although they would target LNG netback prices or equivalent to that[12]. LNG netback prices would be close to the average export price (fob or ex port) of around $11.80 per GJ currently, less LNG processing costs.

.So despite the significant increase in supply thanks to the Gorgon and Wheatstone developments, prices in the Western Australian market are also set to rise in coming years.

[8] (WA Government, 2011)
[9] (IMO, 2014, p. 7)
[10] (Deloitte Access Economics, 2014, p. 14)
[11] (IMO, 2014, p. 115)
[12] (Woodside, 2013)

3. A HIGHER OUTLOOK FOR EASTERN AUSTRALIAN GAS PRICES

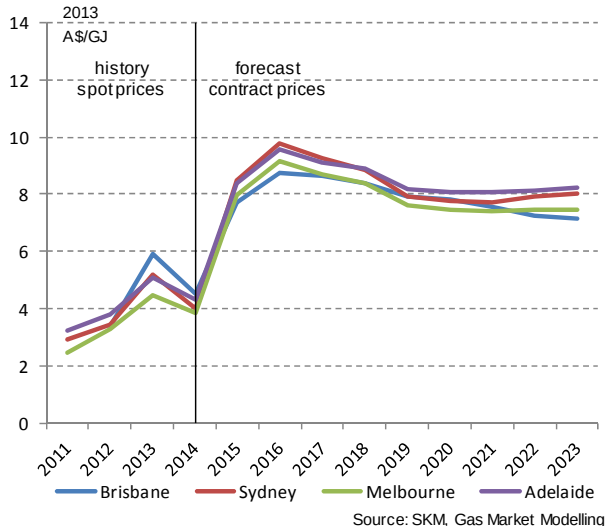
As the previously discussed changes work their way through gas markets across Australia, gas prices are set to rise substantially from their historical averages of around $3-$4 per GJ across the east coast[13] and $2-$3 per GJ on the west coast[14]. A significant amount of research has been performed surrounding the likely outlook for gas prices across Australia and this paper will use this existing research to underpin its analysis of the impact of rising gas price rises on the manufacturing sector and greater economy. This section explores the existing research and selects appropriate existing price forecasts for the western and eastern domestic gas markets.

3.1 Summary of existing identified gas price forecasts and their assumptions

Charts 3.1 & 3.2 present two sets of forecasts for gas prices across the eastern markets. Whilst these forecasts are not directly comparable and are based off a range of differing assumptions they do paint a similar picture of a short term spike before prices settle at a higher level over the medium to longer term. This reflects the impact of supply constraints in the near term before increasing production costs and linkage to international demand pushes up costs over the longer term. Other price forecasts by Energy Quest and ACIL Allen were also investigated which saw prices at 2023 range between $7-$9 and $6-$9 respectively, but the IES & SKM forecasts were deemed the most appropriate.

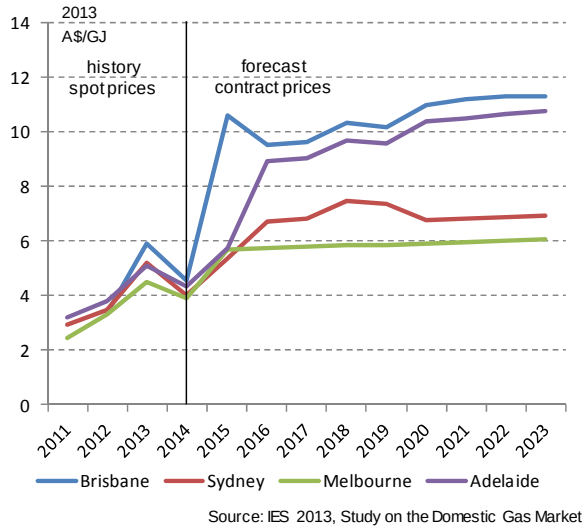
Historical prices for 2010/11 through 2013/14 are *spot* prices from the AER[15], and the original forecasts for 2014 have been replaced with the most recent spot price data to give the most up to date picture. Although this data is not directly comparable with the forecast *contract* prices we feel it is the best available substitute that provides a historical perspective and that an upwards trend can be observed.

Chart 3.1: Sinclair Knight Merz forecasts



Source: SKM, Gas Market Modelling

Chart 3.2: Intelligent Energy Systems forecasts



Source: IES 2013, Study on the Domestic Gas Market

The original 2014 forecasts by SKM and IES were well above the spot price actuals, but this difference can be mostly attributed to delays in the construction of LNG export terminals. Both these forecasts were built on assumptions that 8 trains would be operational by 2023, with SKM

[13] (BREE, 2013, p. 17)
[14] (Economics and Industry Standing Committee, 2011, p. xx)
[15] (AER, 2014)

assuming the 6 committed trains (then under construction) would come online from 2014 through 2016[16], whilst IES assumed they would come online in 2015 and 2016[17]. It now appears likely that these projects will face further delays and we are assuming varying start dates through 2015 with full export capacity to be achieved over 2016.

The May 2014 GSOO update also revised down its forecasts for demand from both the LNG export and domestic segments of the market[18]. However the impact of this was tempered by accompanying downwards revisions to supply estimates. With electricity demand continuing to fall and environmental requirements softening there are also examples of excess gas previously committed to gas powered generation and industrial use being released to the domestic market which has helped soften spot prices in 2013/14.

A brief summary of the assumptions underpinning the forecast scenarios is provided below. It must be noted that multiple scenarios were presented by IES and SKM and that the forecasts presented here refer to the base case scenarios or those deemed most likely by BIS Shrapnel.

3.1.1 Intelligent Energy Systems (IES) forecast assumptions

- Perfectly competitive market where participants cannot exercise market power
- Ignores the influence of existing bilateral contracts
- Domestic demand to fall across the eastern markets
- New production from NSW basins commencing in 2018/19
- Melbourne not linking to netback prices thanks to constraints in transporting gas from the Gippsland, Otway and Bass basins to Gladstone for export
- 8 LNG trains operational by 2023
- Production and transportation costs average $5.60/GJ but trend up over time

3.1.2 Sinclair Knight Merz (SKM) forecast assumptions

- Incorporates the influence of suppliers exercising market power
- Incorporates committed bilateral contracts to determine demand for and timing of new contracts
- 8 LNG trains operational by 2023
- Constant production and transportation cost of $4.65/GJ

It must be noted that the base production and transportation costs forecast by IES and SKM are both higher than the historical price averages. This highlights that regardless of linkages to higher priced international markets, prices are trending upwards thanks to the increasing cost of extraction and transportation. However it is likely that the significant increase in demand from the LNG projects has contributed to the need to exploit higher cost reserves and invest more in infrastructure. There have been recent anecdotal reports that the marginal cost of coal seam gas of the Arrow Energy deposits in the Surat basin was between $7 to $8.85 per GJ at the well head, with transmission costs to be added to this.

[16] (SKM, 2013, p. 22)
[17] (Intelligent Energy Systems, 2013, p. 30)
[18] (Australian Energy Market Operator, 2014)

The key point here is that assuming the higher production and transportation costs of either SKM ($4.65/GJ) or IES ($5.60/GJ) plus a (say) 15% profit margin, prices in the eastern gas market are likely to be at least $5.60-$6.60/GJ, or close to double historical averages, even without the exercise of market power and profiteering by gas producers.

3.2 BIS Shrapnel forecast assumptions

3.2.1 Domestic demand

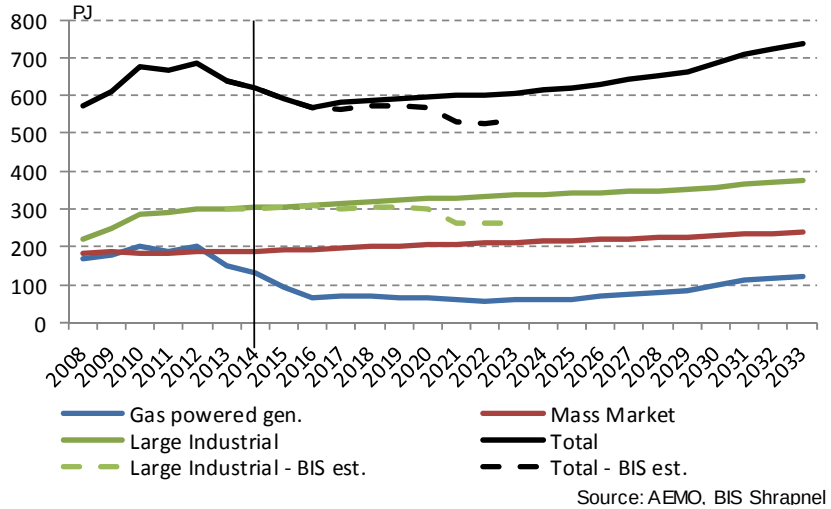
Our expectations for domestic demand fit roughly with the projections included in the 2013 GSOO (see chart 2.1), except for the large industrial segment.

- **Gas powered generation (GPG)** is set to decline as weaker electricity demand, the removal of the carbon tax, the availability of coal as a cheap alternative and increasing gas prices all contribute to limit demand from the GPG segment of the market. This trend is already eventuating, with Stanwell Corporation announcing its intention to close its gas-fired Swanbank E power station west of Brisbane as thanks to weaker electricity demand; they can make more money from selling the gas than they can from using it to generating electricity[19].

- Demand for gas from the **'mass market' (MM)** sector is anticipated to grow steadily at 1.2% p.a. off the back of a solid economy and strong population and household growth. This will be primarily driven by the residential sector across the eastern states.

- The **'large industrial' (LI)** sector is also anticipated to see trend growth of 1.2% p.a. over the forecast period by AMEO. This will be driven by increasing economic activity and assumed positive economic growth in energy-intensive industries across New South Wales and Queensland. However, given increasing supply shortages, particularly from late this decade, and the expectation of 'demand destruction', as manufacturers in particular respond to high gas prices by either switching from gas-fired energy to coal-fired energy where possible, or by simply shutting down because the high prices render their local operations to be uneconomic.

Chart 3.3: Annual domestic gas demand – east Coast markets



[19] (Moore, 2014)

Consequently the outlook for domestic demand is a relatively flat one, with growth forecast by AMEO to average only 0.9% annually out to 2033 (chart 3.3). This fits with the GSOO and is roughly in line with the IES and SKM forecast assumptions of a subdued outlook for domestic gas demand. BIS Shrapnel projections, incorporating the effects of the gas price hike (see section 4.2.3) and the 'worst case' scenario of significant supply shortages in 2023 (see section 4.2.2), actually sees overall demand decline in the period to 2023.

3.2.2 LNG Demand

Our expectation is for 7 LNG trains in Queensland to be fully operational by 2023. This will be made up of the 6 trains that are currently under construction and that are expected to have begun exporting in full by the end of 2016. It also includes the development of an additional train over the forecast period. The Arrow LNG project does not appear likely to proceed as a separate project and we assume that Arrow will instead opt to sell its gas reserves to or opt into a joint venture with one of the existing LNG developments. Arrow is currently in discussions with the other LNG players but at the time of writing no decision has been reached. Therefore we assume that one of the existing LNG projects will expand by adding a third train over the forecast period. It must be noted that there is significant upside to this scenario with the expansions outlined in table 2.1 remaining possibilities over the medium to longer term.

As these 7 trains come on line annual LNG export demand is expected to gradually ramp up to 1,790 PJ[20]. This dwarves the outlook for domestic demand and will see LNG exports account for nearly 75% of total gas demand by 2021. It is this surge in demand that will lead to supply constraints emerging despite a weak outlook for domestic gas demand and there remains significant upside to these forecasts.

3.2.3 A lack of market competition

We also assume that suppliers and producers will exercise market power in setting gas prices in the domestic market. Due to a limited number of operators in this space and infrastructure constraints across the domestic gas market it is far from a perfectly competitive one. This is supported by the Ai Group's survey which found many businesses had difficulty securing a supply contract on favourable terms[21] as well as comments by the Woodside CEO that they would target LNG netback prices in their discussions of recontracting with the NWS[22].

The vertically integrated structure and international linkages of key players such as Origin and Santos gives them significant market power in the domestic gas market. As gas producers and suppliers to both domestic and international markets, these players will be able to divert gas from the domestic market to international markets. This will directly link the domestic market to international prices and in the likely event of production shortfalls for LNG export ensure that these shortages are transferred to the domestic market.

3.2.4 IES vs. SKM

We feel that the SKM modelling fits best with the assumptions we have adopted through our research and with the most recent trends in price data. The key advantage of these forecasts is that they incorporate the capacity for suppliers and producers to exert market power, which we feel is key to understanding the observed and forecast gas price paths in the market and is something the IES forecasts are lacking. The relationship between the different east coast

[20] (Jacobs SKM, 2014)
[21] (The Australian Industry Group, 2013)
[22] (Woodside, 2013)

markets in the SKM forecasts also seems more in line with reality than the IES scenarios. Prices across the different markets have shown a much tighter relationship in recent data than IES suggests and we feel that the assumption that Victorian markets will remain isolated from the price pressures associated with LNG export is unrealistic. Despite our differing assumption surrounding the number of trains coming on line (7 compared to SKM & IES's 8) we are able to adjust LNG demand expectations accordingly and feel that this is not a significant shortcoming. As a result we will be primarily using the SKM price forecasts as the basis for our analysis.

4. WHAT WILL BE THE IMPACT OF RISING GAS PRICES AND LNG EXPORTS

4.1 Impact on residential gas prices, households and the CPI

4.1.1 Impact of higher gas prices on households and CPI

We estimate that the annual gas bill of Australian households will increase by $260 on average, or 26 per cent over the next four years, from the current average of $997 to $1,259, although this may ultimately be a conservative estimate. The hike in residential gas prices will be driven predominantly by significant increases in wholesale gas prices. It will also add 0.2 percentage points to the annual CPI inflation over the next four years (see accompanying tables). By states, Victorian residents will incur the highest additional cost. Our model suggests that annual household gas bill for Victoria will increase by $296.64, on average, over the next four years. South Australian households will incur an additional cost of $291.89, followed by New South Wales $274.99, Queensland $270.10 and Western Australia $209.81.

In terms of the impact on CPI, we estimate that higher gas prices will add 0.3 per cent to Melbourne and Adelaide CPI inflation and 0.2 per cent to Perth consumer price inflation over the next two years. The impact is slightly less in Sydney and Brisbane (+0.1%) as household gas expenditures as a proportion of total household expenditure (and the CPI basket) in these states is lower than for Perth, Melbourne and Adelaide households. CPI data is only published for capital cities and not by state.

Note that we did not estimate the impact of higher gas prices on electricity prices, although it is likely that there could be some marginal impacts from higher peak prices (for which gas generation is mainly used). Nor did we estimate any price rises for some of the manufactured food products which may raise prices due to higher gas prices. These would be largely restricted to non-tradeable goods (such as bread), where cost increases can be passed on, but we feel this relatively small group would have a very minor impact on the CPI.

4.1.2 Methodology: modelling the impact of higher gas prices on household gas bills and CPI

The additional cost to the household gas bill was derived as follows:

- We first obtained, through desk research, the annual average household gas bill for 2013/14 for the five main states ie New South Wales, Victoria, Queensland, South Australia and Western Australia. The Australian average household bill was derived as an average, weighted by the population in each state.
- This actual spend for 2013/14 was then disaggregated into its three main components ie wholesale gas price costs, network charges and retailers' costs. The percentages applied to obtain the splits (in dollar values) were sourced from state regulatory authority publications as well as independent consultant reports.
- For example, in NSW, wholesale gas prices generally constitute 22 per cent of the total annual household gas bill. Network charges comprise 56 per cent of the total bill while the remaining 22 per cent constitutes retailers' cost of supplying gas to households.[23] The percentages for other states are very similar, generally within 1 to 2 per cent of NSW proportions.
- We then forecast the growth profile of each of the components of the annual household gas bill.
- Future wholesale gas prices are based on 'new' substantially higher price forecasts produced by Jacobs-SKM (and accepted by state regulatory authorities such as IPART in NSW), as detailed in the previous section.

[23] http://www.ipart.nsw.gov.au/Home/For_Consumers/Why_gas_costs_what_it_does

Table 4.1: Impact of higher gas prices on annual household gas bills and CPI

NSW

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	1,038.77			
Forecasts				
2015	1,154.32	11.12	115.56	0.07
2016	1,248.52	8.16	94.20	0.05
2017	1,277.49	2.32	28.97	0.01
2018	1,313.76	2.84	36.27	0.02

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

VIC

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	1,200.00			
Forecasts				
2015	1,315.10	9.59	115.10	0.14
2016	1,436.76	9.25	121.66	0.14
2017	1,461.41	1.72	24.65	0.03
2018	1,496.64	2.41	35.24	0.04

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

QLD

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	1,052.63			
Forecasts				
2015	1,164.40	10.62	111.78	0.03
2016	1,257.77	8.02	93.36	0.02
2017	1,294.00	2.88	36.23	0.01
2018	1,322.72	2.22	28.72	0.01

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

SA

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	1,074.68			
Forecasts				
2015	1,191.40	10.86	116.72	0.13
2016	1,305.89	9.61	114.48	0.12
2017	1,333.26	2.10	27.38	0.03
2018	1,366.57	2.50	33.31	0.03

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

WA

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	703.46			
Forecasts				
2015	809.26	15.04	105.79	0.14
2016	891.70	10.19	82.45	0.09
2017	900.82	1.02	9.12	0.01
2018	913.28	1.38	12.46	0.01

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

Australia

As at June	Annual Household gas bill at 'new' world parity prices - $	Annual Per cent Change	Annual Increase in dollars	Impact of higher gas prices on CPI - %
2014	996.82			
Forecasts				
2015	1,104.89	10.84	108.06	0.10
2016	1,201.32	8.73	96.43	0.08
2017	1,226.97	2.14	25.65	0.02
2018	1,256.87	2.44	29.90	0.02

Source: BIS Shrapnel, AER, State Regulatory Authorities, ABS

Table 4.2: LNG Cost and Employment

Project	State	Status	Indicative Cost Estimate $m	Construction Employment Estimate	Operating Employment Estimate
Australia Pacific LNG (trains 1 and 2)	QLD	under constr.	24,700	6,000	1,000
Queensland Curtis LNG project	QLD	under constr.	19,800	5,000	1,000
Gladstone LNG	QLD	under constr.	18,000	5,000	1,000
Arrow LNG Plant	QLD	approved	5,000		
Curtis Island LNG expansion	QLD	possible		na	400e
Gladstone LNG expansion	QLD	possible			
Aut Pacific LNG expansion	QLD	possible			
Gorgon LNG	WA	under constr.	54,000	10,000	3,500
Wheatstone LNG	WA	under constr.	29,000	5,000	400
Scarborough FLNG	WA	possible	14,000		
Prelude Floating LNG	WA	possible	12,600		
Gorgon (train 4)	WA	possible	12,000		
Browse LNG	WA	possible	5,000		1,000
Equus	WA	possible	2,000		
Ichthys LNG	NT	under constr.	33,000	4,000	700
Bonaparte Floating LNG	Timor Sea	possible	13,000		
Cash Maple Development	Timor Sea	possible	5,000		
Crux LNG	Timor Sea	possible	5,000		
Sunrise Gas project	Timor Sea	possible	5,000		
East Coast			67,500	16,000	3,400
WA/NT			161,600	19,000	5,600
Timor Sea			28,000	0	0
TOTAL			**257,100**	**35,000**	**9,000**

e) estimate

Source: BIS Shrapnel, ABARES

Table 4.3: Mining Sector Snapshot – IVA, Employment, Sales and Profits 2012/13

Industry	Industry Value Added $m	% of Total Mining	Employment[1] '000s	Sales[2] $m	Profits[3] $m	Profit Margin (profits as % of sales)
Coal Mining	16,909	14.8	43,380	48,518	1,671	3.4
Oil and Gas Extraction	29,682	25.9	18,682	38,822	25,686	66.2
Metal Ore Mining	58,862	51.4	68,536	92,821	29,671	32.0
Non-metallic mineral mining and quarrying	2,625	2.3	12,745	5,797	-313	-5.4
Exploration and other mining support services	6,366	5.6	46,350	15,189	-2,783	-18.3
Total mining	**114,443**	**100.0**	**189,692**	**201,147**	**53,932**	**26.8**

1. As at end June 2013
2. Sales and service income
3. Operating profit before tax

Source: BIS Shrapnel, ABS data

- Future network charges were obtained from known AER network price determinations and existing submissions of new price proposals by network owners and/or operators. If this information was unavailable, particularly for later years, we used our in-house CPI inflation forecast as the escalator. We believe that this is a reasonable and realistic approximation as most the current round of network enhancement projects are close to completion and growth in capital expenditure later this decade is likely to be aligned to increases in consumer prices.
- Increases in retailers' costs were assumed to grow in line with retailers' margins. This was fixed at the mid-point (6.8 per cent) of IPART"S reasonable range for retail margins of gas retail suppliers of 6.3 to 7.3 per cent.[24]
- The total annual household bill over the next four years was derived as the sum of wholesale gas prices, network charges and retailers' costs.
- The growth rate of each series was multiplied by the gas contribution to CPI to generate the additional contribution to CPI inflation.

In summary, a move toward international parity prices will significantly add to annual household gas bills across Australia. This will impact more severely on the purchasing power of lower income households.

4.2 Impact on the General Economy and the Manufacturing Sector

There will be both positive and negative impacts on the economy from the development of the LNG projects, the likelihood of gas shortages and the sharp rise in gas prices, described in sections 2 and 3.

On the positive side, export revenues will increase significantly over the next decade, from an estimated $16 billion in the 2013/14 financial year to $74 billion in 2022/23 (see table 4.14 in section 4.3). Construction and investment activity has already been substantially boosted, but the major portion of this activity has now been mostly done and will wind down over the next few years as the LNG projects are completed and come onstream (see chart 4.1). This will see the large boost to direct employment from the construction phase wind down from around 35,000 at its peak and be ultimately replaced by 9,000 jobs for the operational phase (see table 4.2).

However, these positive impacts will be accompanied by negative impacts resulting from these LNG developments, namely the sharp rise in gas prices and potential gas supply shortages. Although gas prices in the domestic market in Western Australia are set to rise significantly over the next few years, the west coast market is not expected to experience any supply shortages. But in the east coast market, the domestic gas market is expected to experience a price spike in 2016 (chart 3.1) and potential gas shortages, with the potential gas shortages slowly becoming apparent by late this decade and then worsening sharply in the early 2020s. Accordingly, we will model the analysis of these impacts with reference to the consequences of the east coast LNG expansion.

4.2.1 The Manufacturing sector will suffer the largest negative impacts

The industries which will suffer the largest negative impacts from either (or both) higher gas prices or gas shortages will be those industries which have two or more of these characteristics:

- Higher ratios of gas use intensity per unit of production, usually meaning they will incur higher costs

[24] IPART, Changes in Regulated Retail Gas Prices from 1 July 2014, p.27.

Table 4.4: Industry Snapshot – GVA, Employment, Sales and Profits, 2013/14

Industry	Gross Value Added $m	% of GDP	Employment[1] '000s	Sales[2,3] $m	Profits[2,4] $m	Profit Margin[2] (profits as % of sales)
Manufacturing	101,586	6.5	930	367,030	28,702	7.8
Mining	163,700	10.4	269	225,618	90,040	39.9
Construction	119,616	7.6	1,026	279,315	24,908	8.9
Professional, Scientific & Tech Serv.	98,127	6.3	904	177,128	17,571	9.9
Transport, Postal and Warehousing	72,406	4.6	590	127,883	20,745	16.2
Rental, Hiring & Real Estate	41,772	2.7	204	74,074	31,827	43.0
Electricity, Gas, Water & Waste Serv.	36,457	2.3	152	58,996	12,302	20.9
Accom & Food Services	34,746	2.2	758	78,640	8,211	10.4
Agriculture, Forestry & Fishing	33,372	2.1	313	-	-	-
Total Other Industries	870,934	55.5	7,266	1,433,031	106,044	7.4
Total	**1,471,130**	**93.7**	**11,482**	**2,454,685**	**311,648**	**12.7**

1. Year average
2. Total Other Industries and Total exclude Agriculture, Forestry & Fishing, Public Administration & Safety, Education & Training, and Healthcare & Social Assistance
3. Income from sales of goods and services
4. Gross operating profits

Source: BIS Shrapnel, ABS data

Table 4.5: Manufacturing Sector Snapshot – GVA, Employment and Sales, 2013/14

Industry	Gross Value Added $m	% of Total Manufacturing	Employment[1] '000s	Sales $m
Food, Beverages & Tobacco	24,405	24.0	223	97,011
Textile, Clothing & Other Mfg	5,422	5.3	95	12,615
Wood & Paper	6,635	6.5	62	22,445
Printing & Recorded Media	3,943	3.9	41	8,119
Petroleum, Chemicals & Rubber	18,035	17.8	85	81,875
Non-metallic Mineral Products	5,574	5.5	35	16,001
Metal Products	17,239	17.0	138	66,122
Machinery & Equipment	20,332	20.0	202	62,841
Total Manufacturing	**101,586**	**100.0**	**930**	**367,030**

1. Year average

Source: BIS Shrapnel, ABS data

Table 4.6: Manufacturing Sector Snapshot – Trade, 2013/14

Manufacturing Subsector	Domestic Demand $m	Exports $m	Imports $m	Trade Balance[1] $m	Export Propensity[2] Per Cent	Import Penetration[3] Per Cent
Food, Beverages and Tobacco	89 022	21 970	13 981	7 989	23.2	15.5
Textiles, Clothing & Footwear	17 982	2 194	13 328	-11 134	29.4	71.4
Wood & Paper Products	24 813	2 275	4 643	-2 368	10.3	17.6
Printing & Rec Media	8 999	90	970	- 880	1.1	9.7
Petroleum, Coal & Chemicals	123 050	10 835	52 010	-41 175	12.7	42.2
Non-Metallic Minerals Products	18 266	198	2 463	-2 265	1.1	13.7
Metal Products	54 543	33 521	21 942	11 579	49.0	38.9
Machinery & Equipment	148 221	17 384	102 764	-85 380	28.4	69.5
Other Manufacturing	11 603	1 949	7 785	-5 836	29.4	66.6
Total Manufacturing	**496 500**	**90 416**	**219 886**	**-129 470**	**24.2**	**43.6**

1 Trade Balance = Exports - Imports

2 Export Propensity = Exports/Total Sales

3 Import Penetration = Imports/domestic demand (where domestic demand = Total sales - exports + imports)

Source: BIS Shrapnel, ABS

- Higher levels of trade exposure, with those industries which are more highly exposed to international competition less able to pass on higher costs
- The industry relies critically on gas as a feedstock or critical input into its industrial processes, such as alumina refining, fertilizer production and a range of basic chemical products.
- The inability to switch from gas as an energy source (either in use in generating steam or for drying, or for onsite electricity generation) to other sources, such as coal-fired electricity generation (either on-site or via the grid).

Manufacturing in general, and the sub-sectors of basic non-ferrous metals (mainly involving alumina production, in terms of high gas intensity), non-metallic mineral products (especially ceramics, such as bricks and tiles; and also glass and cement), petroleum, chemical, polymer and rubber manufacturing, iron and steel and parts of pulp and paper manufacturing are among the sectors with both high gas intensity and high trade exposure. These six sub-sectors with high gas intensity (i.e. above 2.5 PJ/$bn of value added) account for 403 PJ or over 89% of the manufacturing sector's gas consumption, but only $31.9 billion (32%) of value added (see table 4.8). Tables 4.4, 4.5 and 4.6 provide a snapshot of industry and manufacturing sales, profits, output (either as real gross value added or industry value added) and export and import propensities. Tables 4.7 and 4.8 detail a history of industry and manufacturing sub-sector gas consumption and gas use intensity ratios. Mining also has a high trade exposure and above average gas use intensity, but a significant portion of the gas is consumed within the oil and gas extraction sector itself, with the use of gas in coal, iron ore and other non-ferrous ores production largely related to the development of pipelines in Western Australia and Queensland which helped these sectors replace more expensive diesel fuel powered electricity generation.

Electricity, gas, water and waste services has the highest gas use intensity but among the lowest trade exposures. However, as evidenced by chart 3.6, it has already displayed some ability to switch from gas powered generation (GPG) to coal-fired generation. This mainly relates to switching from base load GPG. Nevertheless, because GPG has a critical role in the electricity market in terms of both meeting peak (and some intermediate) electricity demand and as a back up to variable renewable generation, there is a limit to how much GPG can be switched to coal-fired generation.

The following analysis will focus on the negative impacts on the manufacturing sector, including flow-on effects to the rest of the economy, while the positive effects will measure the impacts from the higher LNG production and revenues and flow-on effects to the rest of the economy. Two scenarios will be investigated:

- A 'worst case' scenario where all of the shortfall in gas supply in 2023 (see chart 2.3) is concentrated in the manufacturing sector, based on the assumption that gas for the 'mass market' (mainly for the residential sector) and the GPG sector will be provided as demanded.
- A 'short term price hike' scenario related to the spike in prices in 2016 (see chart 3.1). We will assume that the most vulnerable ports of manufacturing shut-down (some permanently), which reduces output and employment.

4.2.2 Worst Case: Impact of the Supply Shortfall in 2023

Chart 2.3 in the previous section shows that, based on the analysis of the Australian Energy Market Operator (AMEO) there will be a serious supply shortfall emerging later this decade. Their most recent update of May 2014 showed that the predicted shortfall was now happening

Table 4.7: Natural Gas Consumption – Industry and Residential

Manufacturing Subsector	Natural Gas Consumption (PJ)								2012/13 Gross Value Added	2012/13 Gas Use Intensity
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	$b[1]	PJ/$b[1]
Mining	146.9	161.0	152.7	170.9	165.5	166.3	173.1	174.5	149.7	1.17
Manufacturing	423.0	435.8	435.1	425.8	438.6	435.1	432.2	451.2	103.7	4.35
Electricity supply	239.0	334.9	367.6	453.6	454.2	468.9	514.6	517.5		
Gas supply	15.2	12.3	12.6	12.3	12.3	12.6	12.6	12.6		
Electricity, gas, water and waste services	254.9	347.9	380.8	467.0	467.3	482.5	528.3	530.7	37.6	14.10
Transport, postal & warehousing	17.9	18.6	19.0	20.4	20.7	21.5	22.1	24.0	73.0	0.33
Commercial and services[2]	42.6	42.5	43.2	45.5	47.8	48.1	47.7	48.1	667.9	0.07
Residential	132.5	134.5	136.9	141.1	144.1	148.1	150.8	154.8		
Total consumed	**1,020.9**	**1,143.5**	**1,170.9**	**1,273.9**	**1,287.2**	**1,304.7**	**1,357.7**	**1,387.1**	**1,525.3**	**0.91**

1. 2011/12 prices

Source: BIS Shrapnel, BREE, ABS

2. Commercial and services comprises all other industries excluding Agriculture, Forestry & Fishing, Public Administration & Safety, Education & Training, and Healthcare & Social Assistance

Table 4.8: Natural Gas Consumption – Manufacturing Sector

Manufacturing Subsector	Natural Gas Consumption (PJ)								2012/13 Industry Value Added	2012/13 Gas Use Intensity
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	$b[1]	PJ/$b[1]
11-12 Food, beverages and tobacco	29.8	29.6	29.9	31.0	31.0	32.3	34.5	35.1	25.6	1.37
13 Textile, clothing, footwear and leather	6.4	6.4	6.1	5.4	5.1	5.2	5.2	5.1	2.7	1.90
14 Wood and wood products	-	-	-	2.1	2.4	1.9	1.6	1.9	3.4	0.56
15-16 Pulp, paper and printing	-	-	-	21.0	22.3	20.6	19.0	17.0	6.2	2.74
17 Petroleum, refining and coal product manufacturing	39.9	39.0	38.7	42.1	40.2	34.1	37.4	37.1	1.4	26.95
18-19 Basic Chemical and Chemical, Polymer and Rubber Product Manufacturing	102.3	96.1	105.8	102.7	117.4	114.8	114.4	126.0	12.8	9.87
20 Non-metallic mineral products	52.2	64.3	59.8	61.9	63.7	67.8	58.9	57.5	5.4	10.68
201 Glass and glass products	10.3	11.1	11.2	12.4	12.8	13.2	12.5	11.5	1.2	9.53
202 Ceramics	18.4	19.0	18.7	18.5	21.5	21.9	17.3	16.5	0.4	39.00
203 Cement, lime, plaster and concrete	19.3	29.9	25.4	26.5	25.1	27.7	24.3	23.9	3.2	7.48
209 Other non-metallic mineral products	4.2	4.4	4.4	4.5	4.2	4.9	4.8	5.6	0.6	9.97
211-212 Iron and steel	23.9	25.9	26.3	21.2	26.7	26.6	19.0	18.6	2.6	7.06
213-214 Basic non-ferrous metals	140.4	145.1	139.6	130.7	122.4	124.0	134.7	146.2	3.5	42.18
22 Fabricated metal products	1.8	1.9	2.0	2.0	2.0	2.0	2.3	2.3	11.0	0.21
23-24 Machinery and equipment	4.4	4.8	4.8	5.2	5.1	5.4	4.8	4.2	20.7	0.20
25 Furniture and other manufacturing	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.1	2.6	0.03
Total Manufacturing	**423.0**	**435.8**	**435.1**	**425.8**	**438.6**	**435.1**	**432.2**	**451.2**	**98.6**	**4.58**
Total Mfg GVA (2011/12 prices)	**106.4**	**107.8**	**111.3**	**104.9**	**105.3**	**104.9**	**104.9**	**103.7**		
Gas Use Intensity (PJ/$bn)	**3.98**	**4.04**	**3.91**	**4.06**	**4.17**	**4.15**	**4.12**	**4.35**		

1. 2011/12 prices

Source: BIS Shrapnel, BREE, ABS

around two years later than their original analysis shown in chart 2.3 (with the dashed line indicating the May 2014 update). Their May Update shortfall analysis only extends to 2020. Given the two year lag to the original forecasts, we have assumed that the 2021 shortfall of 73.5 PJ predicted in their 2013 study now occurs in 2023, with this shortfall projected to remain around these levels for most of the next decade. This shortfall is equivalent to 16.3% of total manufacturing gas consumption of 450.2 PJ in 2012/13 (see table 4.8).

To properly assess the impact of the gas shortage in 2023, we need to measure it against a base case where gas supply is not constrained and grows more or less in line with manufacturing output. BIS Shrapnel's base case forecasts for this analysis are based on the manufacturing gross product forecasts contained in BIS Shrapnel's report, *Long Term Forecasts: 2014–2029*, published August 2014. In this report, total manufacturing real gross value added (GVA) was forecast to grow at a compound annual growth rate of 0.6 per cent per annum over the decade from 2013/14 to 2022/23 inclusive. Although there were variations among sub-sectors, the key gas consuming sectors (with high gas intensity) ranged from 0.4 per cent p.a. (Petroleum, Chemicals, Polymer and Rubber) to 1.3 per cent for Wood and Paper, so the overall 0.6 per cent would be close to the average of the main gas consuming sectors identified in table 4.8.

Using 0.6 per cent p.a. growth for 'unconstrained' gas consumption would yield 478 PJ for total manufacturing gas consumption in 2022/23. The 73.5 PJ shortfall represents 15.4% of this consumption. Our simple assumption is that manufacturing production will be reduced by this proportion in 2023. In terms of direct effects on the gross value of manufacturing production (which is roughly equivalent to the value of sales), this represents a direct loss of $59,278m (in constant 2011/12 prices) compared to the base case, where the value of production had increased at a compound rate of 0.6 per cent per annum from the 2012/13 level. Although we have not separately estimated the impacts across each manufacturing sector, the heaviest impacts would no doubt be felt in the 6 sub-sectors identified as having high gas intensity ratios.

In terms of employment, the direct impact on manufacturing employment is 91,300 fewer jobs.

It is important to note here that this simple analysis and the direct impacts above represent a 'worst case' outcome, or an 'upper limit' for the direct adverse outcomes. It implicitly assumes that steps are not (or are unable to be) taken to mitigate the shortage of gas supply, such as switching from gas to coal-fired electricity, or even on a broader basis, new (extra) gas supply does not come onstream despite the likely higher prices associated with the shortages.

Nevertheless, it is important to recognise the important strategic linkages between and within most of the manufacturing sub-sectors, both among gas intensive and less gas intensive sub-sectors. For example, the basic chemicals sector is a key strategic sector which supplies a range of products for downstream producers in the polymer, paints, pharmaceutical and plastics sectors. It is a sector where natural gas is a key feedstock (input) into its production process, including explosives and fertilisers in particular. In turn, the plastics products (especially packaging) are important to the local supply chain in terms of just-in-time manufacturing abilities, security of supply, specialised products and mutual dependency which tends to place upper limits on price settings by the basic chemical sector itself[25]. For these reasons, some of the downstream sectors may not be able to easily switch to imports. The point here is that although the estimate of the impacts of the supply shortage may appear to be an upper limit, the loss of certain key gas intensive sectors may cause shutdowns further down the chain.

[25] NIER, p.19

Table 4.9: Industry Output Impacts 2023

	LNG: Export Value of 73.5 PJ		Manufacturing: 73.5 PJ gas supply shortage		Net Impacts on Gross Output	Net Impacts on Economy: GDP	as % of Base Case GDP
	Output value	% impact	Output value	% impact	Output value	Gross Value Added	
	$m (2011/12 prices)		$m (2011/12 prices)		$m (2011/12 prices)	$m (2011/12 prices)	
Direct Impacts	806	4.1% (a)	-59278	-15.4%	-58472	-16277	-0.8%
Indirect Industry Output Impacts	185		-51868		-51684	-29491	
Total Industry Output Impacts	991		-111146		-110156	-45768	-2.2%

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

(a) Proportion of expected Queensland LNG production in 2023

Table 4.10: Employment Impacts 2023

	LNG: Export Value of 73.5 PJ	Manufacturing: 73.5 PJ gas supply shortage	Net Impacts on Economy	as % of Base Case Total Employment
	('000)	('000)	('000)	
Direct Impacts	0.0	-91.3	-91.3	-0.7%
Indirect Industry Output Impacts	0.5	-145.1	-144.6	
Total Industry Output Impacts	0.5	-236.3	-235.8	-1.8%

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

Table 4.11: Industry Output Impacts 2016

	LNG: Export Value of 3.1 PJ		Manufacturing Impacts		Net Impacts on Gross Output	Net Impacts on Economy: GDP	as % of Base Case GDP
	Output value	% impact	Output value	% impact	Output value	Gross Value Added	
	$m (2011/12 prices)		$m (2011/12 prices)		$m (2011/12 prices)	$m (2011/12 prices)	
Direct Impacts	34	0.2% (a)	-14203	-3.9%	-14170	-4021	-0.2%
Indirect Industry Output Impacts	8		-12428		-12420	-11687	
Total Industry Output Impacts	41		-26631		-26589	-15707	-0.9%

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

(a) Shortfall of 3.1 PJ in 2016 as a proportion of expected Queensland LNG production in 2016/17

Table 4.12: Employment Impacts 2016

	LNG: Export Value of 3.1 PJ	Manufacturing Impacts	Net Impacts on Economy	as % of Base Case Total Employment
	('000)	('000)	('000)	
Direct Impacts	0.0	-21.9	-21.9	-0.2%
Indirect Industry Output Impacts	0.1	-34.8	-34.7	
Total Industry Output Impacts	0.1	-56.6	-56.5	-0.5%

Sources: ABS, BISS estimates, BIS Shrapnel "Long Term Forecasts:2014 -2029"

In the same vein, the direct impacts of lower manufacturing output and employment have 'knock-on' or indirect multiplier effects which flow-on to activity in sectors which supply inputs to the manufacturing sector or via lower spending caused by the loss of employment and spending, etc.

Based on the 2009/10 Input-Output tables from the Australian Bureau of Statistics (catalogue 5209.0.55.001) we estimate that the industry output multiplier for manufacturing is 1.88. Adding the second-round income and employment effects would give a multiplier of 2.68. For employment, we estimate the industry multiplier to be 2.6.

Manufacturing has a high industry multiplier because it has a high proportion of 'intermediate' inputs from other industry sectors into its final production. The 2009/10 Input-Output tables show that this intermediate input-to-production ratio is 0.706 – or for every $1 of output produced by the manufacturing sector there are 71 cents of other goods and services used in the production process (including from within manufacturing). This compares to only 30 cents for the oil and gas extraction sector and 41 cents for the mining sector as a whole.

In terms of providing a comparison of the direct and indirect value of the positive effects of LNG exports, we have estimated the value of the 73.5 PJ shortfall in 2023 in terms of LNG export revenues. 56.8 PJ of gas is required for one million tonnes of LNG. 73.5 PJ is therefore equivalent to 1.29 MT of LNG, which at the modelled (and close to current) price of A$674 per tonne (see table 4.14 in section 4.3), gives a value of $872 million as a direct benefit (or $806m in constant 2011/12 prices). Employment is assumed to remain unchanged (at around 3,400 at the Queensland LNG plants and gasfields), but for modelling purposes we'll assume some extra indirect employment benefits. For oil and gas extraction (including LNG operation) we estimate the industry output multiplier to be 1.23 (compared to the total mining industry multiplier of 1.7), while the addition of the second-round income effects would lift the multiplier to 1.77. For employment, we estimate the industry multiplier to be 1.88.

The calculations for positive LNG impacts and negative manufacturing-related impacts are detailed in tables 4.9 and 4.10. The net direct impact on industry output is negative $58,472 million. The total net loss of industry output, after accounting for the flow-on multiplier effects on industry, is negative $101,156 million. When the In terms of the base case GDP forecasts from BIS Shrapnel's *Long Term Forecasts: 2014 to 2029* report, this represents a reduction in GDP of 2.2 per cent in the 2022/23 financial year, or $45,768million in total value added terms. Note that we have not included the second round income and employment impacts on the value of output in the estimates in tables 4.9 and 4.11. There are theoretical and methodological issues associated with including the second round employment impacts, including possible double counting, issues of static versus dynamic effects, etc. Accordingly, we have taken a conservative approach and just included the indirect impacts on suppliers to the gas and manufacturing industries as well as the direct impacts on those sectors. If we did add the second round income and employment effects, the net negative impact blows out to $157,146 million.

4.2.3 Impact of the 2016 Gas Price Spike

As discussed in section 2.1.3, a large number of bilateral gas contracts are set to expire in 2015, with research done by SKM indicating almost a quarter of the local gas requirements of the next six years to 2020 are uncontracted. For large industrial users, this equates to around 76 PJ of demand in the eastern states market in 2016. This portion of demand will be the most exposed to the sharp rise in prices (see section 3.1) when prices jump to between $8 to $9.5 per GJ. Furthermore, the latest update by AEMO forecasts a shortfall of 3.1 PJ.

Based on our research, we are assuming that around 20 per cent of the uncontracted and high gas intensity manufacturers exposed to the much higher prices will be rendered uneconomic, and will choose to shutdown. Some of these shutdowns will be permanent, but we expect a

portion will only be temporary in the hope that predictions of a decline in gas prices will eventuate. This will equate to a decline in demand from manufacturers of around 17.5 PJ, including the 3.1 PJ supply short fall. In terms of gas demand from the manufacturing sector compared to the base case, this represents around 3.9% of base demand. Accordingly, overall manufacturing output will be 3.9% lower than the base case.

The direct impact on the value of manufacturing output will be negative $14,203 million. The total net loss of industry output, after accounting for the flow-on multiplier effects on industry, is negative $26,589 million. Note we have only assumed a small positive impact for LNG compared to the base case (based on the expected gas shortfall quantum), as our base case assumed full capacity export and revenue from the Queensland LNG plants.

4.2.4 Comparison with Other Studies – all show negative impacts on GDP and Employment

Over the past two years, three reports have been produced which have attempted to measure the impact of rising gas prices and potential supply shortages on the manufacturing sector and the overall economy.

In May 2013, Manufacturing Australia (the peak representative body for Australia's manufacturing industry) published a brief report titled "Impacts of gas shortage on Australian manufacturing". It analysed manufacturing sub-sectors with high gas usage which were most 'at-risk' from gas shortages, with these industries accounting for $12.6 billion of value added. It concluded that there was a total benefit of $29.5 billion in total value-added ($12.6 billion plus $16.9 billion in indirect flow-on effects) in saving these 'at-risk' industries versus a negative impact on the economy of between $1.1 billion and $4.7 billion via lower domestic gas prices to

LNG exporters (and flow-on effects). The net GDP impact (in terms of value added, rather than the value of production reported above) would be around $25 to $28 billion if the gas was "managed well and supported manufacturing."[26]

In October 2012, The National Institute of Industry Research (NIEIR), published a report titled "Large scale export of East Coast natural gas: Unintended Consequences". NIEIR found that for every "petajoule of natural gas that is shifted *away* from industrial use *toward* export, whether because of tight supply or uneconomic pricing, means giving up $255 million in lost industrial output for a $12 million gain in export output. That is, for every dollar gained $21 is lost. This increases to $24 when economy wide impacts are taken into account."[27]

NIEIR modelled the impact of a scenario where 50 PJ of natural gas was allocated to LNG exports while at the same time an equivalent 50 PJ of natural gas was withdrawn from natural gas dependent industries – not too dissimilar to the 2023 shortfall scenario above where 73.5 PJ is withdrawn from the manufacturing sector and the impact compared to the value of 73.5 PJ of LNG exports and related multiplier effects. In gross output terms, the initial benefit to the $620 million of LNG exports swelled to $1,082 million when the indirect effects were added. The overall negative impact on the gas dependent sectors was -$12,751 million (all $ in constant 2009 prices), which multiplied to -$29,841 million once the other indirect industry impacts were added, giving a net loss to gross output of -$28,758 million. In GDP terms (i.e. value added) the net impact was around -$11 billion, while the impact on total employment was 203,340 compared to the base case, with the loss estimated for the manufacturing sector estimated to be 94,400 jobs.[28]

[26] Manufacturing Australia, p.5
[27] NIEIR, p.ii
[28] NIEIER, p.24, 57-63

Furthermore, NIEIR's modelling indicated "that, by 2042 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas. An alternative 'benefit indicator' used for this study, which combines private consumption, tax receipts and net national product, will be reduced by $46 billion."[29]

NIEIR also focussed on the key chemical sector, finding that "for every $1m of existing chemical industry output that is saved by increased natural gas supply there is another $1m of output that can be obtained by using the competitive advantages for domestic natural gas availability in general, and natural gas liquids in particular."[30]

In July 2014, Deloitte Access Economics' report "Gas Market Transformations – Economic consequences for the manufacturing sector", found that, using SKM's price forecasts (which we have also adopted), the net present value of the cumulative impact on manufacturing output over the years from 2015 to 2021 inclusive would be -$118,069 million or an annual average of $16,867 million, although the initial impact in 2015 is a high $23,199m due to a sharp uplift in gas prices assumed for that year. By 2021, manufacturing employment in the six manufacturing industries selected by the report's sponsors is projected to have been reduced by 14,626 jobs[31], while manufacturing output ends up 4.4 per cent lower in 2021.

In terms of other sectors, gas output was predicted to increase by $80,746 cumulatively over 2015 to 2021 with construction also increasing by a cumulative $38,519 and commercial and services sectors by $1,695 because DAE included the value of LNG construction (and possibly some other related construction and investment) in their modelling. We have not included construction in our analysis (this is discussed in the next section).

A comparison of the direct impacts for gas versus manufacturing reveals a net cumulative output loss of -$37,323. The total output loss is a cumulative $56,931 million over the seven years, but if you exclude the construction and commercial and services sectors, the total output loss is $97,145 million.

Although the estimates of the impacts of different scenarios and assumptions across the three studies and this study vary, the bottom line conclusion is that the economy in net terms is negatively impacted by the expansion of LNG exports and the resulting consequences of significantly higher gas prices and supply constraints. All studies show manufacturing will suffer the largest negative effects.

4.2.5 Negative impacts on Investment

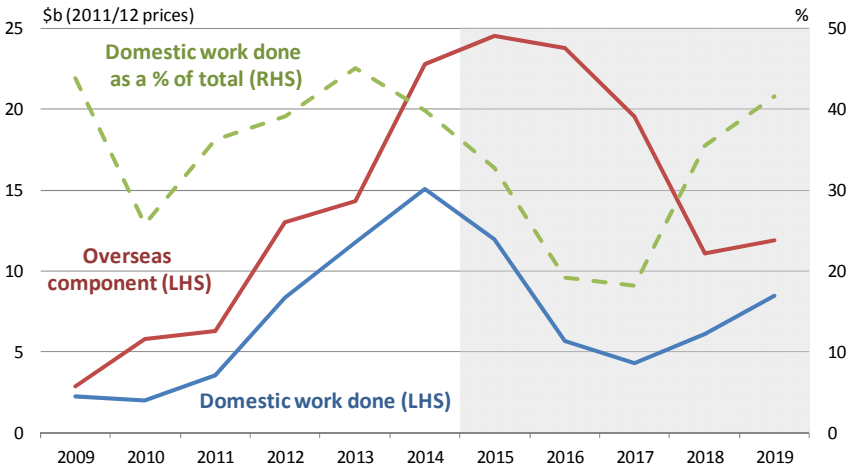
We have excluded the construction and investment impacts from our analysis. Although we could include the estimated value of LNG construction and investment remaining on the projects now under construction and expected to be undertaken (including the Curtis Island LNG expansion by 2020) over the next decade, it is a much more difficult proposition to estimate the quantum of the loss of manufacturing and other investment caused by steeply rising gas prices and supply uncertainty.

Already, there are a number of high profile examples of investment being delayed or moved offshore. Incitec Pivot has announced it will build a US$850 million (around A$940 million) ammonia plant in Louisiana, USA, rather than in Australia as a "strategic response" to high

[29] NIEIR, piii
[30] NIEIR, piii
[31] DAE, p5

Chart 4.1: Domestic vs. Overseas Engineering Construction for LNG

Australia

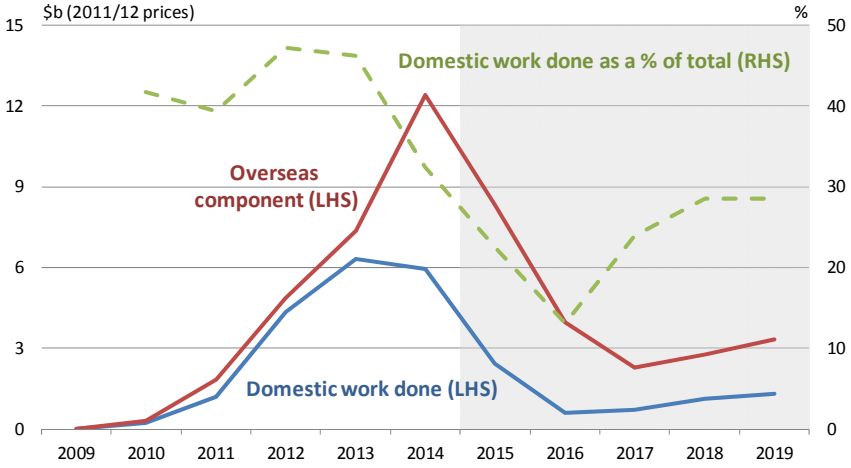


Year ended June

Source: ABS, BIS Shrapnel

Note: Domestic work done and overseas component figures are estimates

Queensland

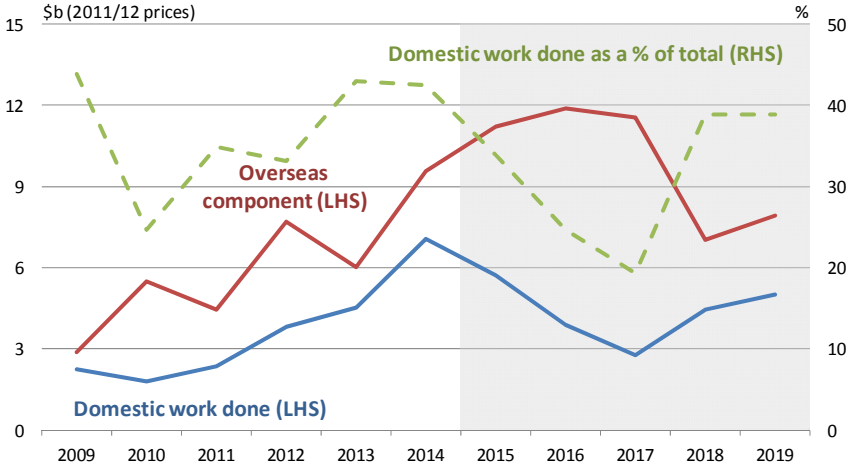


Year ended June

Source: ABS, BIS Shrapnel

Note: Domestic work done and overseas component figures are estimates

Western Australia



Year ended June

Source: ABS, BIS Shrapnel

Note: Domestic work done and overseas component figures are estimates

Australian gas costs. There are recent reports of Perth-based Coogee Energy also considering building a billion dollar methanol plant in the US, rather than Laverton, Victoria because it cannot secure the 50 PJ of gas locally it needs annually for the methanol plant. Meanwhile, BASF (the large German conglomerate) is also warning that $1.5 billion of capital earmarked for Australia will not be spent if there are continuing uncertainties over supply security.

Capital investment expenditure by the mining and manufacturing sectors have considerable downstream benefits for the construction, professional, scientific and technical sectors, rental, hiring and real estate, transport and wholesale sectors, as well as manufacturing, with the construction component of the expenditure usually having a fairly high local content.

However, it should be noted that the local content of LNG construction has fallen considerably over recent years to below 40%, compared to earlier periods when the local content of engineering construction related to LNG was reported to be well above 60%. Chart 4.1 shows the estimated values of domestic versus overseas engineering construction (note the Australian chart includes the Northern Territory), based on data and forecasts contained in BIS Shrapnel's report, *Engineering Construction in Australia: 2013/14 to 2028/29*. The point here is that the flow-on benefits to the Australian industry of the current LNG construction 'boom' are lower than other forms of non-residential construction.

4.3 Impact on net exports and current account

Not all the benefits of increased LNG production and exports flow to the Australian domestic economy. A significant proportion of the extra income will flow overseas in the form of repatriated profits and dividends. Over the 2014/15 to 2022/23 period, remitted profits are expected to total $166 billion, with $49 billion from Queensland alone. Added to this will be a likely significant deterioration in net exports and the end result will be a deterioration in Australia's current account deficit.

4.3.1 Ownership structure of LNG in Australia

In Australia, there are only three projects currently exporting LNG. These are Pluto, which is owned by Woodside Petroleum, Darwin LNG, owned by ConocoPhillips, and North West Shelf, which is part-owned by Woodside Petroleum, BHP Billiton, BP, Chevron, Royal Dutch Shell, and Japan Australia LNG, which is a joint venture between Mitsubishi Corporation and Mitsui & Co. Each of these entities has a one-sixth share of ownership.

Table 4.13: North West Shelf and Pluto Revenue and Profits

		2006	2007	2008	2009	2010	2011	2012	2013
North West Shelf	Total Revenue	2,263	2,237	3,102	2,493	2,749	2,989	3,300	3,230
	LNG Revenue	100	109	1,252	983	1,484	1,709	1,891	1,863
	EBIT	1,675	1,632	2,094	1,722	1,904	2,047	2,235	2,170
	EBIT/Revenue	0.74	0.73	0.68	0.69	0.69	0.68	0.68	0.67
Pluto	Total Revenue							1,427	2,098
	LNG Revenue							1,164	1,702
	EBIT							453	954
	EBIT/Revenue							0.32	0.45

Source: BIS Shrapnel, Company Annual Reports

Table 4.13 shows the level of revenue, profits, and profit margins achieved at the North West Shelf and Pluto (which came on stream in 2012) plants, in calendar years, sourced from Woodside Petroleum's annual reports. Unfortunately, ConocoPhillips currently reports financials for the Asia-Pacific region only, and splits for each country are not provided, hence they are not included here.

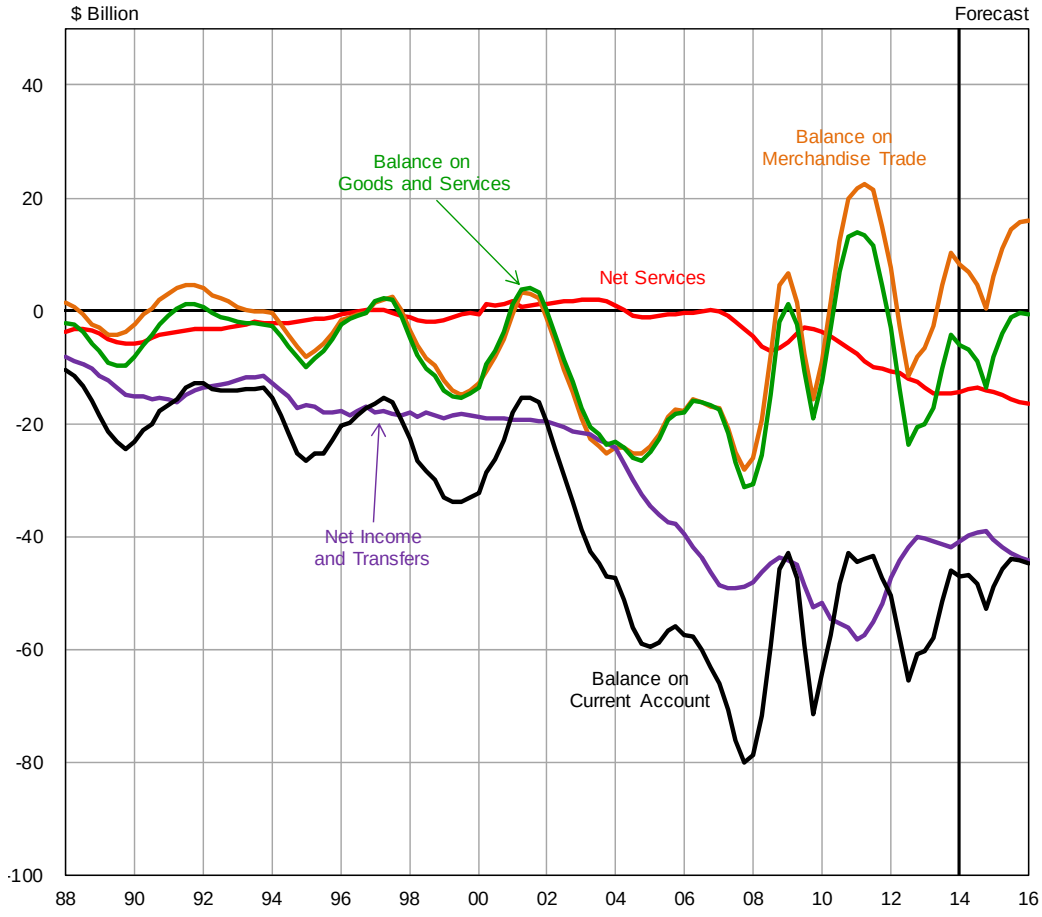
It is worth noting the significant profit margins obtained at each plant, of 67 per cent and 45 per cent in 2013 for North West Shelf and Pluto respectively. These results are consistent with ABS data which suggest the profit margin of the Oil and Gas Extraction industry was 66 per cent in 2012/13, as shown in table 4.3.

4.3.2 Repatriated Profits of the LNG sector to grow significantly

Of the plant owners outlined above, only Woodside Petroleum and BHP Billiton (for the sake of simplicity) are considered to be Australian-owned. The remaining investors are based overseas, meaning that profits are remitted (repatriated) overseas, rather than remaining in Australia. Because of this significant component of foreign-based ownership in the LNG industry, there is a correspondingly large component of profits which flow overseas.

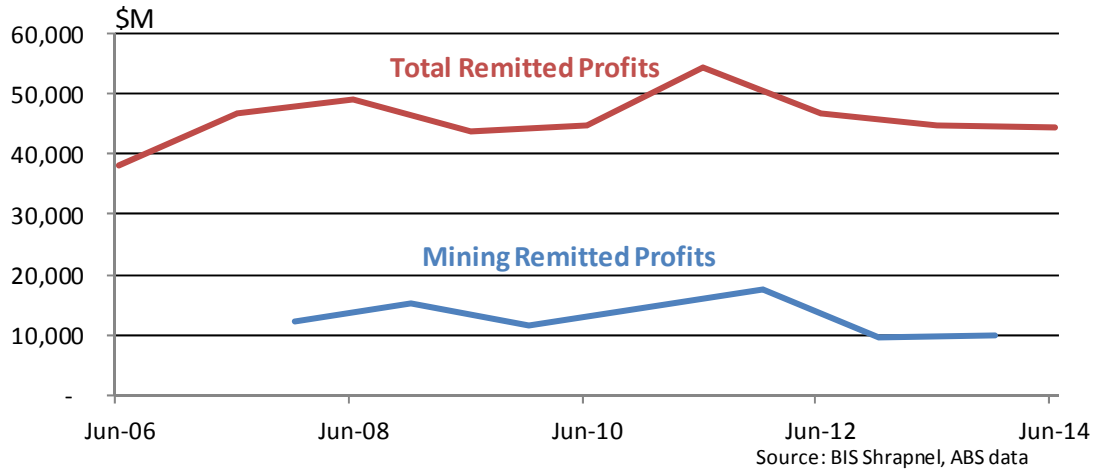
ABS data provide detailed breakdowns of income debits through the Balance of Payments and International Investment Position publication (catalogue number 5302). This data includes the value of profits sent overseas, through remitted profits, dividends, and reinvested earnings. Note that reinvested earnings, while actually remaining in Australia, count toward the total value of repatriated profits because they are essentially a shortcut compared to sending the profits back overseas, before returning to Australia for investment purposes. Remitted profits, dividends and reinvested earnings (essentially returns to equity) now account for just over half of the $87 billion of income debits (with interest payments on Australia's foreign debt comprising 42%). In the accompanying Balance of Payments chart, it can be seen that net income and transfers is the largest component of the Current Account Deficit, with $49 billion in income credits partially offsetting the large amount of profits and interest payment debits.

Chart 4.2: Balance of Payments — Current Account
Moving Annual Totals



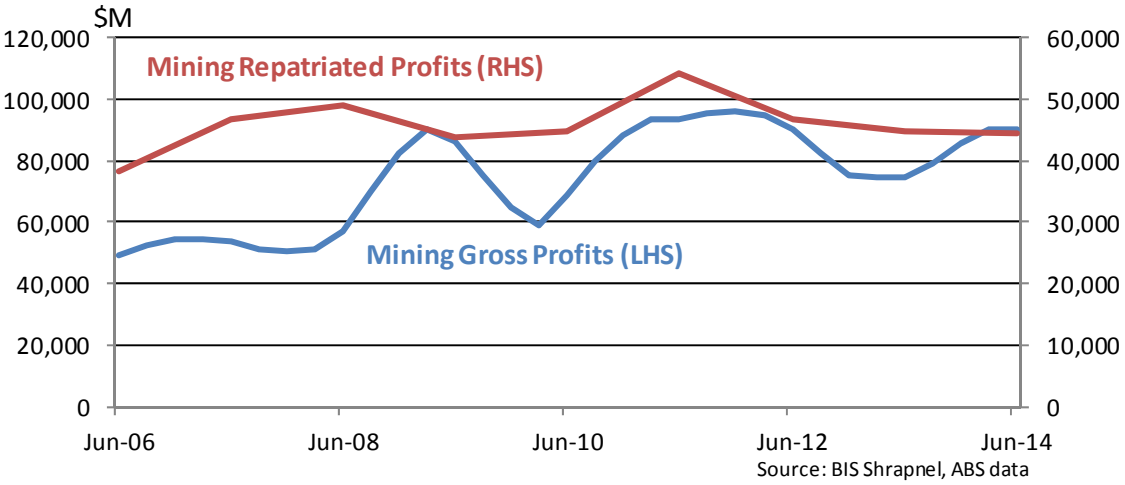
Data on these components at the industry level are less detailed, although still provide a useful guideline of the level of profits leaving Australia. Data are sourced from the ABS' International Investment Position, Australia: Supplementary Statistics publication (catalogue number 5352). Chart 4.3 below shows the value of remitted profits from the mining sector, as well as the all-industry total. Over the seven years for which sectoral data are available, the mining industry has been responsible for between 20 to 30 per cent of all profits repatriated from Australia.

Chart 4.3: Australian Repatriated Profits, All Industry and Mining



Source: BIS Shrapnel, ABS data

Chart 4.4: Australian Profits and Repatriated Profits, Mining Industry



Source: BIS Shrapnel, ABS data

This trend is expected to continue, and indeed accelerate, over the next five years. A number of new LNG projects across Queensland, Western Australia and the Northern Territory are expected to come on stream, and their significant proportion of foreign ownership will ensure that the level of remitted profits from the mining sector continues to rise. Table 4.12 shows the LNG projects which are likely to have reached production by 2019, and the levels of domestic ownership.

Table 4.14: Australian LNG Projects – Ownership, Revenue and Profits

	Australian	Year ended June						
	Ownership	2014	2015	2016	2017	2018	2019	2023
		Expected Output (Mt)						
North West Shelf	33%	16.5	16.5	16.5	16.5	16.5	16.5	
Pluto	100%	4.3	4.3	4.3	4.3	4.3	4.3	
Darwin LNG	0%	3.2	3.2	3.2	3.2	3.2	3.2	
Australia Pacific LNG	38%	0.0	0.0	2.0	6.0	9.0	9.0	
Curtis Island LNG	0%	0.0	1.8	8.3	8.5	8.5	8.5	
Gladstone LNG	30%	0.0	0.4	5.8	8.2	8.2	8.2	
Gorgon	0%	0.0	0.0	1.3	8.3	14.3	15.0	
Wheatstone	0%	0.0	0.0	0.0	1.9	8.8	8.9	
Prelude	0%	0.0	0.0	0.0	1.5	3.5	3.6	
Ichthys	0%	0.0	0.0	0.0	2.1	6.0	8.4	
Exchange Rate	A$/US$	0.92	0.90	0.90	0.90	0.90	0.90	0.90
LNG Price	A$/tonne	672	674	674	674	674	674	674
	US$/tonne	617	607	607	607	607	607	607
	A$/GJ	11.8	11.9	11.9	11.9	11.9	11.9	11.9
Australia								
Total Production/Exports (Mt)		24.0	26.2	41.4	60.6	82.3	85.6	106.1
Total Revenue (A$m)		16,147	17,684	27,944	40,835	55,494	57,740	71,550
Total Profits (A$m) (45% margin)		7,266	7,958	12,575	18,376	24,972	25,983	32,198
Total Repatriated Profits (A$m)		4,297	4,940	8,838	13,965	20,221	21,231	26,511
Queensland								
Total Production/Exports (Mt)		-	2.2	16.1	22.7	25.7	25.7	31.7
Total Revenue (A$)		-	1,474	10,857	15,304	17,327	17,327	21,361
Total Profits (A$) (45% margin)		-	663	4,886	6,887	7,797	7,797	9,612
Total Repatriated Profits (A$)		-	627	4,130	5,458	6,027	6,027	7,616

Source: BIS Shrapnel, ABARE, ABS data, Company Annual Reports

As described above, Woodside Petroleum and BHP Billiton are assumed to be Australian-based, as are Origin Energy and Santos. The remainder are foreign-based, and are therefore assumed to remit all their profits from Australia.

Of the $9.8 billion remitted from the total mining sector in 2013, BIS Shrapnel estimates that $1.9 billion came from the existing LNG projects. This LNG-related figure is expected to swell to $21.2 billion by 2019, due to the start-up of the new, predominantly foreign-owned, plants.

This forecast is made on the basis of several assumptions:

- The Australian dollar is assumed to hold at its current value of US$0.90.
- The Brent oil price, which traditionally has a close relationship with the LNG price, is assumed to remain at its current level of US$103/barrel. Together, these assumptions are expected to translate to an LNG price of A$674/tonne.
- BIS Shrapnel's research into the mining industry is used to estimate the timing of LNG production from each plant. Multiplied by the LNG price, this yields industry revenue.
- The margin used to calculate profits is assumed to be 45 per cent. This is the lower of the North West Shelf and Pluto profit margins shown in table 4.11, but it is lower than 66 per cent average Oil and Gas industry profit margin reported by the ABS, as per table 4.3. Multiplied by the LNG industry revenue, this gives total profits.
- The value of remitted profits is calculated by multiplying the proportion of foreign ownership of LNG plants, by total industry profits.

Table 4.14 shows the significant growth in remitted profits expected over the next five years. There are two primary causes of this – the actual volume of LNG being produced and sold, as well as an increasing proportion of foreign ownership in the LNG industry. LNG production is expected to more than triple over the next five years, from 24Mt in 2014 to 86 Mt by 2019. This is due to the number of projects currently under construction, which will reach the production phase over the next few years.

Of the 24Mt produced in 2014, an estimated 9.6 Mt (40 per cent) are attributable to Australia-owned firms, courtesy of Woodside's 100 per cent ownership of Pluto, and the 33 per cent share of North West Shelf owned by Woodside and BHP. However, many of the forthcoming LNG plants are 100 per cent foreign-owned, including Curtis Island, Gorgon, Wheatstone, Prelude, and Ichthys. As a result, of the 86Mt expected to be produced in 2019, just 15.6MT (18 per cent) will be attributable to Australian firms, exacerbating the flow of funds overseas through remitted profits. This will see the ratio of remitted profits to total mining operating profits increase significantly from its current 12 per cent.

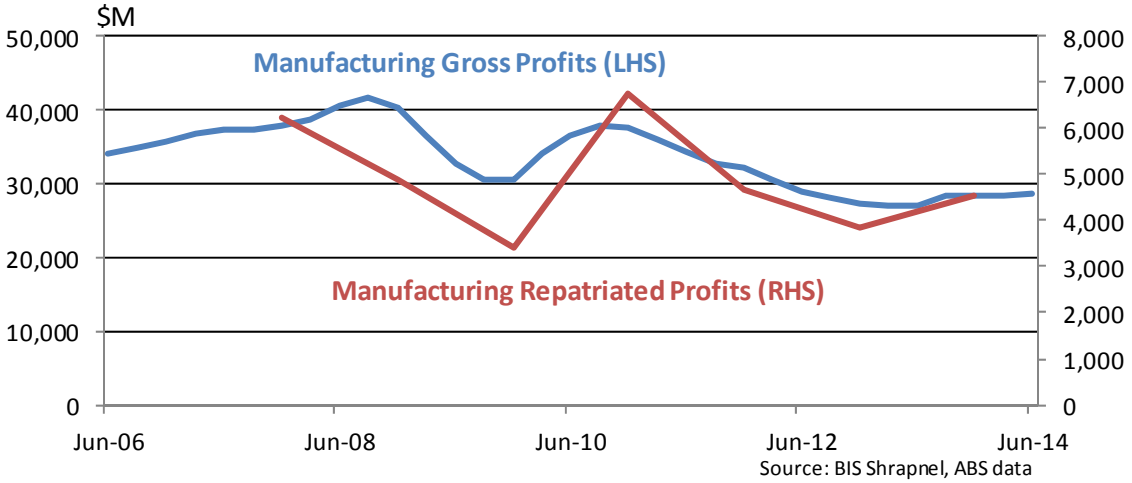
Queensland will be a significant contributor to this trend, as all three forthcoming LNG plants are either mostly or completely foreign owned. From zero LNG production and exports in 2014, output is expected to rapidly increase over the subsequent five years. Repatriated profits are therefore forecast to reach $6 billion by 2019, and continue rising through to 2023 as these established projects undergo expansions.

4.3.3 Remitted Profits of the Manufacturing Sector will decline

The issue of repatriated profits is also present in the manufacturing sector, although traditionally to a lesser degree. The manufacturing sector as a whole has been struggling for several years now, as Australia's high cost base and persistently high local currency have hindered the competitiveness of the sector on a global basis. As a result, business operating profits have fallen a cumulative 30 per cent from the peak of 2007/08 to 2013/14.

Consequently, remitted profits from the manufacturing sector are currently sitting well below the peak levels reached in 2007 and 2010, sitting at $4.5 billion in 2013. Chart 4.3 shows that the level of remitted profits tends to track overall manufacturing profitability, and we would expect this to continue into the future. This means that any further declines in manufacturing output, revenue and profits due to the impacts of higher gas prices or lower gas supply will also be accompanied by a lower volume of profits being repatriated, offsetting some of the loss.

Chart 4.5: Australian Profits and Repatriated Profits, Manufacturing Industry



Source: BIS Shrapnel, ABS data

4.3.4 Imports would escalate, Manufacturing Exports Decline, CAD worsen

We have not attempted to model the full impact of the expected decline in manufacturing output and sales on the merchandise trade balance. However, a worst case scenario decline of $53 billion in the value of manufacturing production would, other things being equal, largely translate to an equivalent worsening in merchandise trade balance. Manufacturing output and sales essentially are a substitution for imports in the domestic market or are exported, so without this production, imports would escalate and exports from the manufacturing sector would decline. In terms of the present manufacturing sector trade balance of -$129 billion (see table 4.6), this would represent a 40% deterioration.

However, imports are very sensitive to movements in national income and expenditure, so the net decline in GDP caused by the direct and indirect effects of the decline in manufacturing output would itself cause much lower demand for imports – perhaps by as much as $30 billion. Nevertheless, this would still see the trade balance deteriorate by over $20 billion, thus wiping out much of the benefit from higher Queensland (and overall Australian LNG exports).

4.4 Other Negative Impacts

4.4.1 Increased Greenhouse Emissions

The increased use of gas for electricity generation and directly by households and industry, at the expense of coal-fired electricity, was supposed to be a critical element in the stabilisation (and possible reduction) in CO_2 and other greenhouse emissions. The data on gas used in the electricity supply sector over the past decade (see table 4.7) suggests this was occurring.

However, this process is now reversing. Chart 3.3, shows a fall in GPG consumption in the eastern market from around 200 PJ to below 60 PJ by 2023, a 70 per cent reduction. Given most (or all) of this will be replaced by coal-fired electricity, this means Australia's greenhouse emissions are set to rise over the next decade. The shutdown of the 385 megawatt Swanbank E gas fired station and restarting of the coal-fired Tarong station is a good example. The gas-fired station produces 50 per cent less greenhouse gas emissions than an average coal-fired plant.

5. HOW HAS POLICY RESPONDED ELSEWHERE?

The experience of the Eastern Australian market is not a unique one, with the surge in global gas demand promoting significant investment in LNG facilities across the globe. Table 5.1 provides a summary of gas exporting countries and their respective policy stances. Whilst there are a number of policy responses that have been enacted in other jurisdictions, many of these would be unpalatable for Australian Governments to even consider, such as nationalising production or setting gas prices. Consequently, we have limited our investigation to those jurisdictions which share similarities with Australia, ie, new entrants to the international LNG export market and their market is not dominated by government-owned companies.

Table 5.1: Summary of gas market policies in selected gas-exporting countries

Country	Annual gas exports	Gas market policies
Algeria	12.6 Mt (LNG)	· Government-owned Sonatrach dominates production · International oil and gas companies must partner with Sonatrach (requires a minimum 51% ownership in production sharing) · Domestic prices are regulated
Egypt	8.6 Mt (LNG)	· 1/3 of gas production must be directed to domestic consumers · International producers required to enter into 50% JVs with state-owned companies · International oil and gas producers receive capped prices and domestic prices are government subsidised · Restriction on new gas export contracts
Qatar	3.6 tcf (LNG and pipeline)	· Government-owned Qatar Petroleum dominates production and controls most projects, with international participation · Downstream industrial gas consumption controlled by Qatar Petroleum · Domestic allocation of gas to vertically integrated downstream uses, although comes with high opportunity cost compared to LNG export value
Indonesia	1.4 tcf (LNG and pipeline)	· Domestic market obligation policy is applied on case-by-case basis to new projects. Reservations of up to 40% have been agreed for new projects · Domestic gas prices are regulated by government below market rates
Malaysia	1.2 tcf (LNG)	· Government-owned Petronas monopolises upstream development · Domestic gas prices subsidised by government
Canada	2.2 tcf (pipeline)	· Gas exports require government licence approval · Approvals are dependent on adequate supply being left for domestic requirements
United States	0.5 tcf (pipeline) 13.1 tcf (LNG conditional)	· Gas exports to non-FTA countries require government approval · exports must be found to be in the 'public interest' by the DOE, which takes into account domestic energy security, the adequacy of supply and the impact on the US economy
Norway	3.5 tcf (LNG and pipeline)	· Government-owned Statoil the dominant producer, with participation from international oil and gas companies · No specific policies to preference domestic consumers · Domestic prices determined by export market
Russia	6.4 tcf (LNG and pipeline)	· State-owned company Gazprom the dominant producer · Significant domestic gas price regulation and subsidisation
Israel	-	· Recent discoveries have significantly increased Israel's export capacity · 450 billion cubic metres of natural gas reserved for domestic use, essentially reserving 60% of Israel's natural gas reserves for domestic use

Source: Eastern Australian Domestic Gas Market Study

5.1 The international experience

5.1.1 The United States

As part of the shale gas boom the United States has seen its domestic gas production increase significantly in recent years. This dramatic increase in supply has pushed down domestic gas prices and promoted investment in a sizeable LNG export industry in a similar fashion as has occurred in Australia. However the US experience has many unique characteristics compared to the Australian experience. The US domestic market is much larger, more dynamic and competitive and its shale gas and oil reserves have proven more profitable to exploit than Australia's CSG reserves. These factors have encouraged significant development, with marketable natural gas production trending up to an all-time high of 26,135 billion cubic feet (Bcf) in the year ended May 2014[32]. With LNG exports yet to commence the increase in production has proven effective in driving down domestic prices and encouraging gas use across domestic industry.

US Public Interest Policy

In the US the export of LNG is regulated by the Natural Gas Act of 1938, where exports must be found to be in the 'public interest' by the Department of Energy (DOE). If the US has a free trade agreement (FTA) with the destination country then the exports are automatically deemed to be in the national interest. With non-FTA countries the DOE will conduct a review and deny an application if it is decided that the exports would be inconsistent with the public interest. It must be noted that the export of gas is assumed to be in the public interest unless it is proven otherwise and hence the onus of proof is on the opponents of the export project.

The definition of 'public interest' is fairly loose, but in assessing previous applications, the DOE has used the following criteria[33,34], although these are not deemed exhaustive:

- domestic need for the natural gas proposed for export
- adequacy of domestic natural gas supply
- US energy security
- Impact on the US economy (GDP), including impact on domestic natural gas prices
- International considerations
- Environmental considerations

The DOE also highlights the importance of allowing the market to set prices (both domestic and export) competitively and stresses that government should not play a role in determining prices.

As at July 31 2014, export authorisations to FTA countries had been granted to 36 LNG projects, for non-FTA countries authorisations had been granted to 8 LNG export projects and 26 export applications were under review[35]. It must be noted that there is significant overlap between these numbers, with many projects applying to export to both FTA and non-FTA countries.

[32] (US Energy Information Administration, 2014)
[33] (United States Department of Energy, 2013)
[34] (Smith, 2013)
[35] (United States Department of Energy, 2014)

The impact of the US LNG exports

The export of LNG from the US was found to have a net economic benefit in reports prepared for the DOE by NERA[36]. However reports by EIA[37] and Deloitte[38] also point out that increasing LNG exports will create upwards pressure on domestic gas prices. The extent of these price rises is dependent on the magnitude of the increase in demand from LNG terminals, which remains uncertain. Deloitte points out that the volume of exports is likely to be relatively small compared to the entire size of US supply, and that the dynamism of the US market will help limit the pressure on domestic prices.

However, with 26 LNG export applications currently seeking approval there is significant scope for LNG demand to increase dramatically and place increasing upwards pressure on domestic prices. Over 16,200 Bcf per annum of exports to FTA countries have been approved, which is over 60% of annual marketable natural gas production[39]. Whilst not all of this will go ahead and Deloitte makes the argument that LNG exports will be anticipated by producers and hence supply will be able to respond to increased demand as exports ramp up to ever higher levels, production will increasingly struggle to keep pace and be forced to exploit higher cost reserves.

The existence of the public interest test allows the US to maintain control over its export volumes and ensure that any increase in LNG demand does not outstrip available supply and create shortages in domestic markets. Thus far the US has not used its national interest test to decline a LNG export application to a non-FTA county, although as mentioned above there are a number of licenses granted to countries with FTAs.

The US State Department has also stated its desire to boost LNG exports as a means to boost American geopolitical influence in respect to Russia[40]. This gives the US a very different set of objectives to Australia and makes it more likely that they will approve projects. Therefore it is likely that US LNG exports will grow strongly in coming years, placing increasing pressure on domestic prices there in a similar fashion to that experienced in Australia. This is unless the US chooses to enforce its public interest test to limit LNG exports.

5.1.2 Canada

Canada has been a net gas exporter for many years, primarily supplying the US market. Production began to slip back in 2007 as reserves were depleted but similarly to the US, new technological advances have seen the exploitation of shale gas, 'tight' gas and coal bed methane reserves support a return to growth in production[41]. The Canadian market is closely linked to the US market and domestic prices there exhibit a close relationship with US Henry Hub prices and thus we can expect them to follow a similar trend.

Canadian National Interest Policy

The Canadian Government has a similar approach to the US for the export of natural gas. The National Energy Board (NEB) is an independent federal agency that is responsible for reviewing and deciding on applications for LNG export licenses. Section 118 of the National Energy Board Act (1985) sets out the criteria against which prospective LNG export projects

[36] (NERA Economic Consulting, 2014)
[37] (US Energy Information Administration, 2012)
[38] (Deloitte, 2011)
[39] (United States Department of Energy, 2014)
[40] (Davenport & Erlanger, 2014)
[41] (US Energy Information Administration, 2013)

are assessed:

> *On an application for a license to export oil or gas, the Board shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada*[42].

The Board also outlines what it takes into consideration when considering an application[43]:

- The source and volume of gas proposed to be exported
- A description of gas supplies, including Canadian gas supply, expected to be available to the Canadian market (including underlying assumptions) over the requested licence term
- A description of gas requirements (demand) for Canada (including underlying assumptions) over the requested licence term
- The implications of the proposed export volume for the ability of Canadians to meet their gas requirements

It should be noted that the Act does not consider environmental matters in making its decision.

As at August 2014, seven LNG export licenses had been granted by the NEB and a further 16 were currently before the board[44]. However at the time of writing, the most advanced LNG project (the Chevron/Apache Kitimat project) was awaiting a final investment decision, although the EPC contract was awarded in January.

The impact of Canadian LNG exports

The export of LNG from Canada will also prove to be a net economic benefit to the Canadian economy. Increased production in the US will see them reduce imports and leave Canada with a surplus of natural gas to its domestic needs. LNG terminals will provide a market into which to sell this surplus. However, similarly to the US (and Australian) experience, too rapid and too large an increase in LNG capacity will see demand begin to outstrip supply and place upwards pressure on prices. This would impact negatively on the local industry and manufacturing sector in the same manner as in Australia (see section 4). With the linkages between the US and Canadian markets gas prices in both markets move in tandem and hence the gas policy of one country will impact on the other.

The national interest test provides a means to control LNG investment and limit excess demand from this segment of the market. Thus far the NEB has not ruled against any LNG projects, but with a further 16 applications for LNG export licenses before the NEB the national interest test may prove more important in coming years as gas users in the US and Canada, such as Dow Chemical are beginning to raise concerns over the impact of LNG exports on domestic gas supplies[45].

5.1.3 Is a national interest test in the national interest?

In the US and Canadian experience the existence of their respective 'national interest' policies has thus far not limited investment in the natural gas sector. Although these markets are very

[42] (Government of Canada, 2014)
[43] (Government of Canada, 2014)
[44] (Government of Canada, 2014)
[45] (Lewis, 2013)

different to the Australian market and are unlikely to see the same extent of price rises, they do face the same concerns of excessive LNG exports creating supply constraints in domestic markets. Invoking the national interest tests to knock back export licenses has not been deemed necessary thus far, but their existence helps act as an insurance policy against excessive LNG exports, giving the respective governments of Canada and the USA more control over their natural resources and the capacity to ensure that their domestic industries are not hurt in an attempt to cash in on the natural gas boom.

5.2 The Australian domestic experience

Across Australia there is currently no national gas reservation policy or export control policy. In the Energy White Paper 2012[46] the Australian Government put forward its position on domestic gas reservation:

> *the Australian Government does not support calls for a national gas reservation policy or other forms of subsidy to effectively maintain separation between domestic and international gas markets or to quarantine gas for domestic supply*

However, the separate state/territory jurisdictions have taken different approaches to their respective natural gas reserves:

5.2.1 New South Wales

In May 2012 a New South Wales parliamentary inquiry into CSG recommended that the NSW Government implement a domestic gas reservation policy, under which a proportion of the CSG produced in NSW would be reserved for domestic use. It argues that such a policy could assist to contain price increases, enhance energy security, and reduce the State's dependence on coal for power generation[47]. This recommendation was dependent on the expansion of the State's CSG industry.

The NSW Government responded to this recommendation in October 2012 saying that such a reservation policy was unnecessary. It argued that prospective CSG fields were not linked to LNG exports and that the gas would only be used in New South Wales anyway. It also highlights concern that a reservation policy would be a disincentive to investment and add to development costs. The Government also notes that it would be willing to reconsider this stance once the CSG industry in New South Wales is better established[48].

It must be noted that we feel that the assumption that prospective CSG fields in New South Wales will not be linked to LNG exports is a difficult one to make. A proposed Queensland Hunter Gas Pipeline has been under consideration for some time in one form or another and whilst it is currently on hold indefinitely and unlikely to proceed, its consideration highlights an appetite to link New South Wales gas to the Queensland and LNG export markets. Hence if producers are not forced to dedicate gas to the domestic market then we see no reason why they would choose to do so at prices below international netback prices, particularly with Santos being involved in both the Narrabri gas fields and the Gladstone LNG project.

5.2.2 Queensland

Queensland doesn't have a gas reservation policy but it does have a Prospective Gas Production Land Reserve (PGPLR) policy. This policy allows the Government to limit the gas

[46] (Department of Resources, Energy and Tourism, 2012)
[47] (NSW Government, 2012, p. xx)
[48] (NSW Government, 2012, p. 12)

produced in certain areas for the Australian gas market when tenure is granted. The Government can enact the policy if supported by the annual Gas Market Review process or if gas supply becomes constrained or is forecast to become constrained[49].

The 2012 Gas Market Review recommended that the PGPLR policy not be implemented on the basis that LNG projects had already reached final investment decisions. However in the event of further investment in LNG trains, depending on the response of the liquidity of the domestic gas market the future enactment of the PGPLR policy may be considered[50].

5.2.3 Western Australia

Western Australia is the only Australian state/territory with a domestic gas reservation policy. This policy stance is outlined in more detail in section 2.2, but amounts to a commitment to negotiate on a case-by-case basis for the equivalent of 15% of production from LNG export projects to be reserved for domestic consumption. The 15% target is based on forecasts for WA's domestic gas consumption that were calculated in 2006 and are subject to periodic review. The next such review will occur during 2014/15.

The existence of a domestic gas reservation policy has done little to slow investment in natural gas and LNG in Western Australia. Since the Western Australian Government formalised its policy in 2006, roughly $88 billion of construction has occurred in the oil & gas sectors, providing a significant boost to the economy (see table 5.1).

Table 5.2: Oil & gas investment in WA

Subsector	2005/06 - 2013/14 incl. $m, 2011/12 prices
Gas field	31,679
Other LNG	38,981
LNG	70,660
Other Oil and Gas	17,559
Total Oil and Gas	88,219

Source: BIS Shrapnel, ABS

Despite the existence of this policy, there remain concerns that gas prices in Western Australia will face the same pressures as are evident across the east coast. The supply commitment from the NW shelf JV is nearing fulfilment and with this source accounting for a sizeable proportion of WA's supply (approx. 42% in 2014), upwards pressure on prices will intensify upon its expiry.

5.3 How successful have these policies been?

A national interest test

Despite the existence of national interest policies in the US and Canada there are still concerns that domestic gas prices there will rise as they become increasingly linked to international markets. Although the existence of these policies gives the respective governments the ability to control exports and limit demand from this segment of the market. This would help prevent any supply shortages in the domestic market, limiting any upwards pressure on domestic prices.

The US Congress is currently debating whether to change its policy and further open up LNG exports, with the Republicans and BHP Billiton arguing in favour of such a move, whilst Democrats and large manufacturers (Industrial Energy Consumers of America) such as Dow Chemical and Incitec Pivot are lobbying to maintain preferential access to cheap gas domestically. Australian policy is being used as an example of how not to export gas, citing the

[49] (QLD Government, 2011, p. 6)
[50] (Department of Energy and Water Supply, 2012, p. x)

impact it has had (and will have) on Australian gas prices and manufacturing (citing the DAE report). Mr Fazzino from Incitec Pivot told legislators he chose to develop an ammonia plant in Louisiana instead of Australia because of its business-friendly regulation and access to cheap and copious amounts of domestic gas[51], highlighting the benefit of cheap and plentiful gas in promoting the domestic manufacturing industry.

The US & Canada both have much more dynamic and diversified domestic gas markets than Australia, which has helped limit gas price rises there, but we feel that this has little to do with the national interest policy as it is yet to be enacted. A key criterion of both countries' national interest tests is ensuring an adequate supply of gas for domestic use and hence the policy can act as a de facto reservation of gas for domestic consumption, depending on how it is utilised. However, the relatively ambiguous nature of the test and the influence of political considerations can create significant investment uncertainty.

Domestic gas reservation

A domestic gas reservation policy has the benefit of essentially quarantining a portion of gas production from the influence of international markets. In Western Australia, despite them having had an LNG export industry since 1989, such a policy was able to guarantee domestic supply at attractive prices, whilst still allowing investment in the LNG industry and a healthy level of exports. The concerns now arising are more due to the expiry of the NWS JV's reservation commitments and highlight the importance of ensuring that any reservation policy is sufficient over the longer term.

The key is ensuring a reservation proportion that is sustainable for suppliers, producers, exporters and consumers. Reserving too high a proportion of natural gas production for domestic use, whilst driving domestic prices down, would place a significant impost on gas producers. Consequently, investment in new exploration, production and export capacity would suffer as it became unfeasible and the nation would not realise the benefits from its natural resources, with supply concerns likely to emerge over the longer term. Reserving too low a proportion of natural gas production would be ineffective and see prices continue to rise with the associated negative impacts on industry outlined in section 4. Therefore any introduction of a domestic gas reservation policy must devote significant time and energy into the proportion of production reserved, and remain flexible in its application.

[51] (Kehoe, 2014)

6. HOW SHOULD POLICY RESPOND HERE?

6.1 Summary of results/findings

The era of cheap and abundant supplies of gas for Australia's domestic users is over. Historical gas prices of around $3-4/GJ are set to at least double or triple within two to three years, due to the huge demand for gas for export, via a raft of LNG developments in Western Australia, the Northern Territory and Queensland. With export prices close to $12/GJ, gas producers are expected to divert supply to the LNG plants as 5 major plants (3 in Queensland) progressively come onstream over the next two years.

Domestic supply is not an issue in Western Australia thanks to that state's domestic gas reservation policy (although prices will rise). But in the eastern states' market – which is mostly interconnected by an extensive pipeline network – the lack of a gas reservation policy for domestic users is not only leading to higher prices, but also potential supply shortages as gas producers chase higher export returns while supply increases at a slower rate than previously expected.

While the Australian economy will derive positive benefits from higher LNG export revenues, these will be outweighed by much larger losses to production and national income because of the substantial negative impacts on Australian manufacturing, in particular, and other associated industries, resulting from higher prices and supply shortages. There will also be significant employment losses in the affected industries, but few permanent jobs created by ongoing LNG production.

In effect, this will see a substantial transfer of national income from Australian gas-using industries to the gas and LNG producers. However, as there is a high level of foreign ownership in these sectors, a significant portion of the higher profits will leak overseas as remitted profits and dividends. The loss of manufacturing production will also see a marked rise in imports and lower manufacturing exports, with the worsening trade deficit adding to the higher remitted profits and causing a sharp deterioration in the Current Account Deficit.

Meanwhile, households are also negatively impacted with the annual gas bill expected to rise by $260 (26 per cent) over the next four years. This effectively represents a transfer from households to the gas producers of over $2 billion.

The genesis of the looming crisis in gas prices and supply lay in the original decision to approve not one but three huge LNG developments in Gladstone, Queensland, all based on coal seam gas (CSG) extraction – an industry arguably still in its infancy in Australia – and all to be developed virtually simultaneously and come onstream within a year of each other. Given the substantial amount of gas wells to be developed within a relatively short space of time and potential technical difficulties, it should have been apparent that enough supply for the plants could be an issue.

These issues and the potential impacts of not ensuring there would be sufficient, reasonably priced gas available for domestic markets represents a serious policy failure. It is apparent that the assessment process and economic evaluation – in terms of the national interest – for the Queensland LNG plants was deficient, both by the State and Commonwealth Governments. Perhaps it would have been prudent to approve only one or two CSG-based LNG projects, and allow subsequent CSG LNG plants after a proper assessment.

The current ambitious plan to speed up the approval and development of more CSG wells and lift production in NSW and Victoria is not the answer. Without a domestic gas reservation or equivalent policy, there is still no guarantee that the increased CSG production will not be

diverted to the Queensland LNG plants, via the existing pipeline network and (probably) a short extension from Narrabri to the Queensland network. The domestic requirements of local industry and households need to be addressed as a matter of urgency.

6.2 Policy prescription

With the impacts outlined above we feel that allowing the unfettered export of LNG will be a net negative for the Australian economy and that there should be a policy response to ensure that the benefits of our natural gas reserves are best shared across the nation. In considering both a national interest test for export licenses and a domestic gas reservation policy we feel that a reservation policy would be most effective in maintaining affordable gas domestically, supporting domestic industry and encouraging investment in the oil and gas sectors.

As discussed, a national interest test can act as a de facto domestic reservation policy, but we do not see it as being as effective as a reservation policy. The approval or denial of a licence would create a more 'all or nothing' proposition, whilst a reservation policy, if not too onerous, could provide an optimal domestic outcome, whilst supporting investment in an LNG export industry, as witnessed in Western Australia.

6.2.1 How would we reserve gas domestically?

The WA reservation policy is based on forecasts for domestic gas demand that were made in 2006 and it is due to be reviewed in 2014/15. A similar method could be used to determine the proportion of gas to be reserved for domestic use across the west and eastern markets. Based off the projections for demand (both for domestic use and LNG) included in the 2013 Gas Statement of Opportunities for eastern and south-eastern Australia, domestic demand in these markets is expected to account for close to 30% of total production by 2023. In Western Australia, this proportion is much lower at approximately 10%[52]. Nationally (excluding the Northern Territory) domestic demand makes up 15% of total demand, however in order to reduce pressure on prices a moderately higher proportion around 20% would be advisable to provide some slack in the market.

An alternative approach would be to forecast the domestic demand for natural gas in absolute terms over a predetermined period and then apply this result as a proportion of reserves. Using Core Energy forecasts of domestic demand and known reserves from the 2013 GSOO[53] 25 years of domestic demand would be equivalent to 37% of 2P reserves or 15% of 2P, 3P & 2C reserves. However by linking to reserves and not production levels this could create difficulties in matching actual supplies with demand in the short term.

It must be noted that these forecasts were made under the assumption of no domestic reservation policy and the downwards pressure such a policy would place on prices would reverse some demand destruction and promote higher demand domestically. Hence more work is required to determine a final proportion of gas production to be subjected to reservation. These examples highlight that there is a degree of flexibility in determining a domestic reservation policy that is conducive to both an optimal domestic outcome and a healthy LNG export industry. Any policy must be arrived upon in conjunction with producers in order to ensure that it does not have a dramatic negative impact on exploration and production and simply create supply constraints further in the future. This would likely mean that a reservation policy would have to be limited to new investment in order to limit sovereign risk and maintain the viability of existing projects.

[52] (IMO, 2014)
[53] (Core Energy Group, 2013)

6.2.2 Impact on Gas Producers' Profits

What would be the impact on gas producers' profits with a 20% reservation in the East Coast markets? One way to look at it would be to estimate the impact on profits if the east coast markets had such a policy in the first place (as there should have been) when the three large CSG LNG projects were approved initially.

Using the assumptions set out in section 4.3.2 and table 4.14 indicates that at full capacity of 25.7 Mt in 2018, the three plants would make a collective profit of $7,797 million, assuming a 45% margin. 20% of that profit is $1,559 million. Assume the margin on domestic gas is 15%, giving a margin of $1/GJ on the cost of production and transportation (using IES's cost of extraction and transportation of $5.60/PJ – see section 3.1.1). We estimate $1/GJ is around 19% of the export margin, so the profit of the 20% of gas sold in the domestic market is $291, which represents a 'loss' (in terms of export opportunity cost) of $1,268 million.

Combining the profits of the gas sold on the LNG export market ($7,797) and the domestically sold gas ($291 million) gives an overall profit of $8,088 million, which represents an overall margin of 40% (rather than 45% if all gas was sold as LNG exports) and a profit loss of around 14%, compared to if all the gas was sold on the LNG export market. Of course these estimates are sensitive to the profit margin assumptions.

We should also highlight the effect of the exercise of market power in just the domestic market on gas producers' profits, using the SKM price assumptions (and their assumption of suppliers using market power – see section 3.1.2). Assuming SKM's average cost of production and transportation of $4.65/GJ and the average price of $9.31/GJ in the east coats markets in 2016 – which is the peak in prices because of the exercise of market power – the average gross margin is 50%. Using the higher costs of production and transportation used by IES of $5.60, but still using SKM's price, the margin is 40% in 2016. As shown in chart 3.1, domestic prices ease after 2016, under the assumption of increasing supply (and weak demand). In 2023, at the average east coast market price of $7.72 modelled by SKM, the gross margin on domestic gas sales is still a healthy 25% to 39%, relative to the IES and SKM cost assumption respectively.

These above margins need to be put in perspective. The ABS data presented in table 4.4 shows that the overall gross margin for all reported industries is 12.7%, Mining is almost 40%, for all industries excluding Mining the margin is around 10%, while the Manufacturing sector is only 7.8%.The upshot is that if one assumed the 20% gas reservation would lead to sufficient domestic supply, and therefore less ability to exercise market power, then domestic prices and gas producers' margins would also be lower, but even assuming a 15% margin, they would still be higher than most other industries.

Nevertheless, with such high profit margins, one could make the argument they can afford a modest cut in profits in order to support Australian industry and help lower greenhouse gas emissions.

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