Pipe Dream

A Financial Analysis of the Northern Gas Pipeline

Institute for Energy Economics and Financial Analysis
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Executive Summary

Construction of the North East Gas Interconnector (NEGI) is being proposed at a time in which global liquefied natural gas (LNG) markets are in a glut. The NEGI deal—if it were built—would occur under a monopoly arrangement whose economic benefits, if there are any, would be limited to foreign owners.

This report explores the many risks in how the project is structured financially and how it is being proposed in the face of declining markets.

Highlights of our finding are shown in this Executive Summary, followed by our full analysis.

Recent capacity downgrades for the project suggest demand for the project is overstated.

There appears to be much less customer demand than predicted for the North East Gas Interconnector (NEGI), proposed originally as an A$800m pipeline to connect the Northern Territory with the East Coast gas markets of Australia.

The proposal has had a 25% capacity downgrade since its first design and was resized in April 2016 from 14- to 12-inch pipe, suggesting a reduced capital cost to A$650m.

The pipeline would run for 623 kilometres from Tennant Creek to Mount Isa.

The project raises questions, in addition to those around whether it is needed, over ownership.

The Northern Territory government has awarded the pipeline contract to Jemena, a company effectively owned by the Chinese and Singaporean governments (via State Grid Corp. of China (60%) and Singapore Power (40%)). The deal between the government and the project owners would allow for an unregulated and largely untaxed monopoly. The NEGI can charge whatever tariffs it sees fit. And if development of gas resources in the Northern Territories proceeds, the monopoly service providers would accrue most of the economic benefits.

The project would most likely be a loss-making enterprise

Australia's entire East Coast onshore gas export industry, a high-cost player in the global context, is running at a loss. The gas it produces is expensive at the wellhead, is expensive to transport across an unregulated transmission network and is expensive to liquefy in high-capital-cost plants. The sole advantage the industry has is its relatively proximity to its major markets in North Asia.

The project is informed by official energy-market forecasts that are too high.

Australians have been poorly served by government agencies and semi-government agencies responsible for making forecasts of global and domestic demand for gas. The Australian Energy Market Operator (AEMO), responsible for making domestic demand forecasts has been chronically inaccurate on this point and professionally negligent, failing to take into account basic economic factors such as the effect of price on volumes.

The Office of the Chief Economist (OCE), responsible for global gas demand forecasts, which is forecasting large rises in demand for liquid natural gas (LNG) in Australia's key market, the North Asian market and in our view has failed to take into account global competitive forces and changes in the technology of energy production.

The project is being built into a global glut in LNG

The global LNG market is currently oversupplied, with 245Mt sold in 2015 compared to global liquefaction capacity of 308Mt. That surplus is at 26% and rising. Indeed, the global LNG industry is in a demand crisis that is particularly acute in North Asian markets critical to Australia. Demand for LNG from Australia's three largest markets—Japan, Korea and China—declined in aggregate over 2015.

European gas markets are reporting a supply glut as Russia and Norway defend their market share. The U.S. is rapidly ramping up supply into Europe, and volumes may be displaced from Europe into the higher-priced North Asian LNG market.

Global LNG supply is likely to rise rapidly through 2020, with liquefaction capacity expected to reach 400 Mtpa in 2020, an increase of 30% from 2015, which means more capacity is being added to a market already over supplied.

A Breakdown Is Occurring in How Contracts Are Traditionally Priced

LNG entering the Japanese market has been priced off oil, but with the advent of the U.S. becoming a major exporter, the oil-linked contract is a thing of the past. LNG in the future will increasingly be priced off gas indices such as the Henry Hub price. Long-tem term contracts themselves may be subject to "renegotiation." This has recently occurred with Qatar's Rasgas and India's Petronet and resulted in a reported halving in the price over the 25-year term of contracts.

Northern Territory Production Is Very High Cost

Northern territory onshore gas fields are higher cost than the currently loss-making Eastern Australian onshore export gas fields. Northern producers also have to contend with large distances to get their product to market. It is little wonder that Jemena has not signed any customers apart from the Northern Territory government-owned Power and Water Commission (PWC).

Conclusion

For the NEGI to be built, substantial new fossil fuel subsidies from the Northern Territory government (through the PWC) and the federal government (through the Northern Australia Infrastructure Facility) will be required.

The NEGI has been conceived to compensate for a poor decision by the PWC to contract to buy too much gas. The commission overestimated demand, a common failing of government agencies, and is attempting now to on sell that gas. The NEGI is likely to fail, however, as it is a bad decision being promoted to cover up another bad decision.

Neither the NEGI nor the larger East Coast onshore gas export market has sufficient customers for their high-priced product.

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1. The Project

On 17 November 2015 Jemena announced that it had won the tender to build the North East Gas Interconnector (NEGI).[1] Jemena has proposed to use McConnell Dowell as the engineering and construction firm. On completion the pipeline will be renamed the Northern Gas Pipeline.

The NEGI is a proposed 623km pipeline linking Tennant Creek in the Northern Territory to Mt Isa in Queensland. It would connect the Northern Territory with the Eastern gas market. The original proposal involved a capital construction cost of $800m.[2]

The final investment decision is expected to be taken in December 2016.[3]

First gas is expected to flow to the east coast markets from mid-2018.

The project is a two-stage project with the second stage to be built at an indeterminate date in the future. Managing Director of Jemena, Mr Paul Adams stated:

> *"As soon as sufficient gas is proven in the NT, Jemena will seek to build a further link connecting Mt Isa to the Wallumbilla hub in Queensland. This will vastly improve the reliability of the gas transmission network by reducing sole reliance on Moomba as the hub for supplies. It will also introduce some much-needed competition into the east coast market, while accelerating the growth of the NT gas sector."*

The NEGI is being built to open up the Northern Territories undeveloped unconventional gas resources. Its cornerstone customer is the Northern Territories Power and Water Commission (PWC). The PWC contracted too much gas for its customers and needs to on sell that gas.[4] Incitec Pivot has a phosphate deposit and fertilizer manufacturing facility near Mount Isa and needs gas for processing. Incitec has contracted with PWC to buy 10PJ per annum for the 10 years beginning mid-2018.[5]

Currently, Incitec's operations at Mt Isa are supplied with gas by the 840km Carpentaria Gas pipeline which runs from Ballera to Mt Isa. Its capacity is 119TJ/day (this compares to the NEGI's 90TJ/day capacity).

The gas being sold by the PWC to Incitec is sourced from conventional gas sources in the Blacktip field in the Bonaparte Gulf off the Northern Territory coast and the Dingo field in the Amadeus Basin.

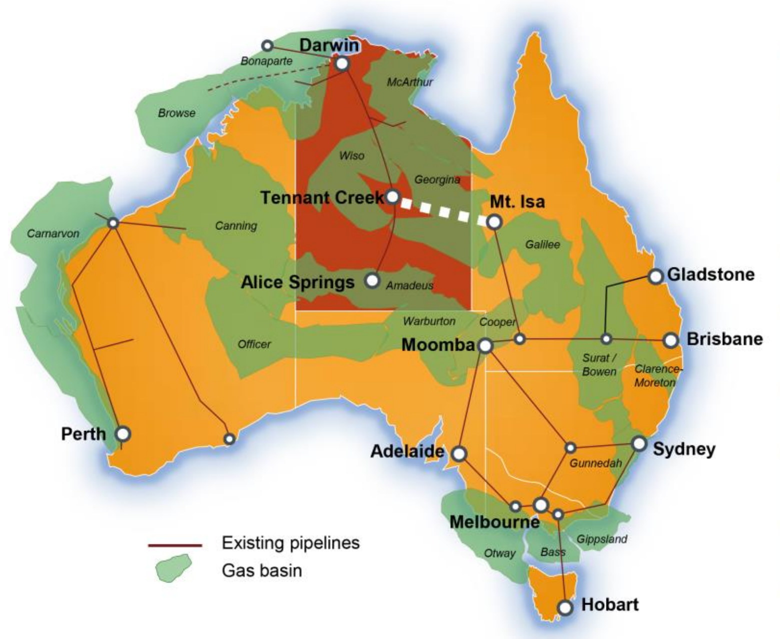
In total PWC has around 25-35PJ a year of contracted but unused gas supply that could be shipped on the NEGI. Volumes of 25-35PJ a year are not sufficient to make a material difference to the overall supply/demand dynamic on the east coast of Australia as they represent <2% of the volume of the total market (export and domestic).

[1] https://jemena.com.au/about/newsroom/media-release/2015/jemena-to-build-north-east-gas-interconnector
[2] Page 24 Jemena 2015 annual report: http://jemena.com.au/getattachment/About/investors/annual-reports/Financial-Statements-for-the-year-ended-31-December-2015.pdf.aspx
[3] http://www.energynewspremium.net/storyview.asp?storyID=826958390&section=On+the+Record&sectionsource=s121&aspdsc=yes&utm_medium=email&utm_campaign=ENP+Standard2015-11-25&utm_content=ENP+Standard2015-11-25+CID_f8da02dc34d653bb8d37d5e2eaa297ef&utm_source=C
[4] https://theconversation.com/connecting-the-dots-the-northern-territory-enters-the-eastern-gas-market-51463
[5] http://phx.corporate-ir.net/external.file?t=2&item=o8hHt16027g9XhJTr8+weNRYaV9bFc2rMd0Q/AXw4zssiqldSpokIlSvKOFErJHPfH+hT4gOL2t2Ea5Oo0ghyL0WUoM+gQvtiOqiuYgV+5jWOaAr/jon7skP2s2PgdOkWnoDnx4h688ink3efQJnOA==&cb=63583330013420410

The initial capacity of the pipeline was proposed to be under 100 million cubic feet per day (110,000 GJ per day) - about a seventh of an LNG train. It is less than 5% of the east coast domestic gas market.[6] It is likely that the NEGI will make little difference to the supply demand balance on the East Coast even if it ran at capacity.

Figure 1.1: Northern Gas Pipeline

NORTHERN GAS PIPELINE



Location	Tennant Creek to Mt Isa
Distance	622 Km
Size	14 inch
Entire project costs	$800m
Construction start	2017
Commissioning	2018
Construction Employment	900+ FTE
Operations employment	30 FTE

Source: *Northern Territory Government 2015*

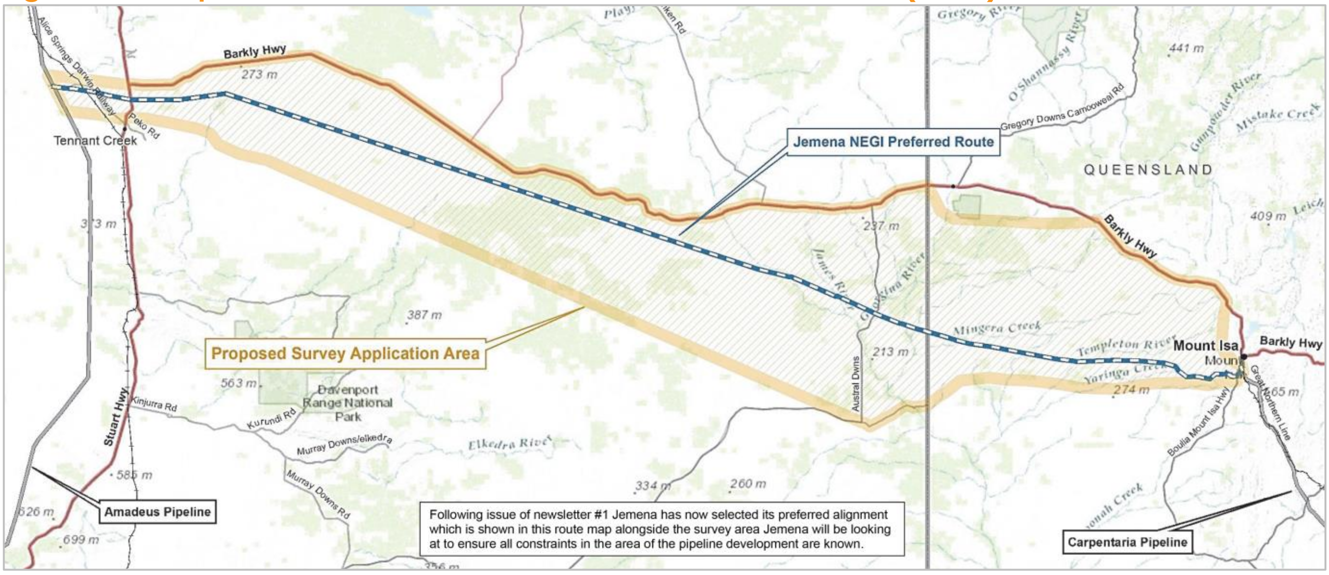
In April 2016 the pipeline proposal was downgraded 25% in size following a lack of interest in using the pipe. Jemena has been unable to sign up any other customers beyond the agreement between PWC and Incitec. The NEGI will be able to carry just 90 TJ a day of gas through a 12 inch diameter pipe instead of the 110 TJ a day of gas through a 14 inch pipe that was originally proposed when the company won the tender in November 2015.[7]

The distinct lack of customers has jeopardised the ambitions for the stage 2 extension of the pipeline network from Mt Isa to Wallumbilla.

[6] http://www.energynewspremium.net/storyview.asp?storyID=826958390&section=On+the+Record&sectionsource=s121&aspdsc=yes&utm_medium=email&utm_campaign=ENP+Standard2015-11-25&utm_content=ENP+Standard2015-11-25+CID_f8da02dc34d653bb8d37d5e2eaa297ef&utm_source=C

[7] http://www.smh.com.au/business/energy/gas/jemena-forced-to-reduce-nt-gas-pipeline-size-amid-drilling-opposition-20160401-gnwgmc.html

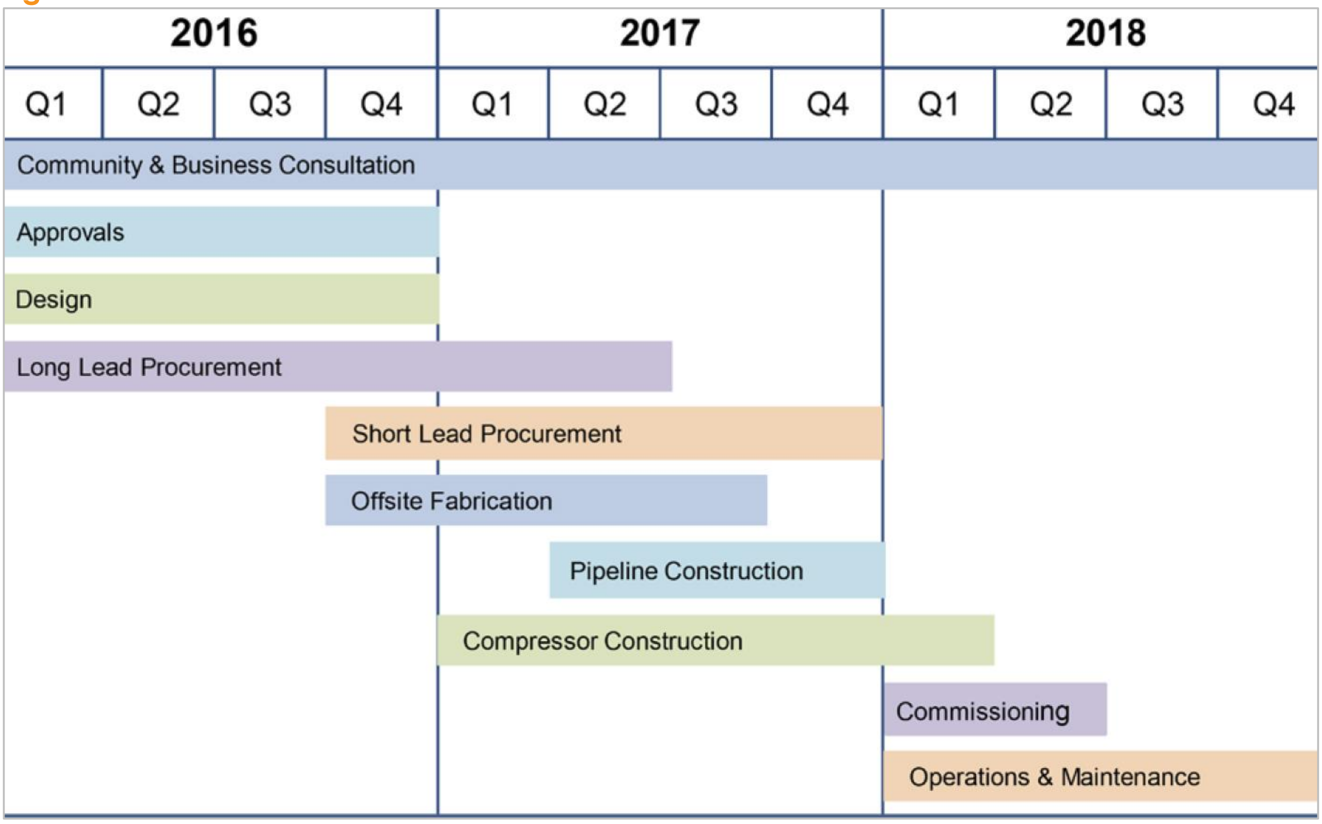
Figure 1.2: Proposed Route of the North East Gas Interconnector (NEGI)



Source: *Community Newsletter May 2015*

If the NEGI should proceed it is the PWC (in effect the Northern Territory government) that is underwriting the project. The PWC is paying a high price to find a market for gas that it purchased to fulfill demand that has not materialised.

Figure 1.3: Timeline for the NEGI



Source: *Community Newsletter March 2016*

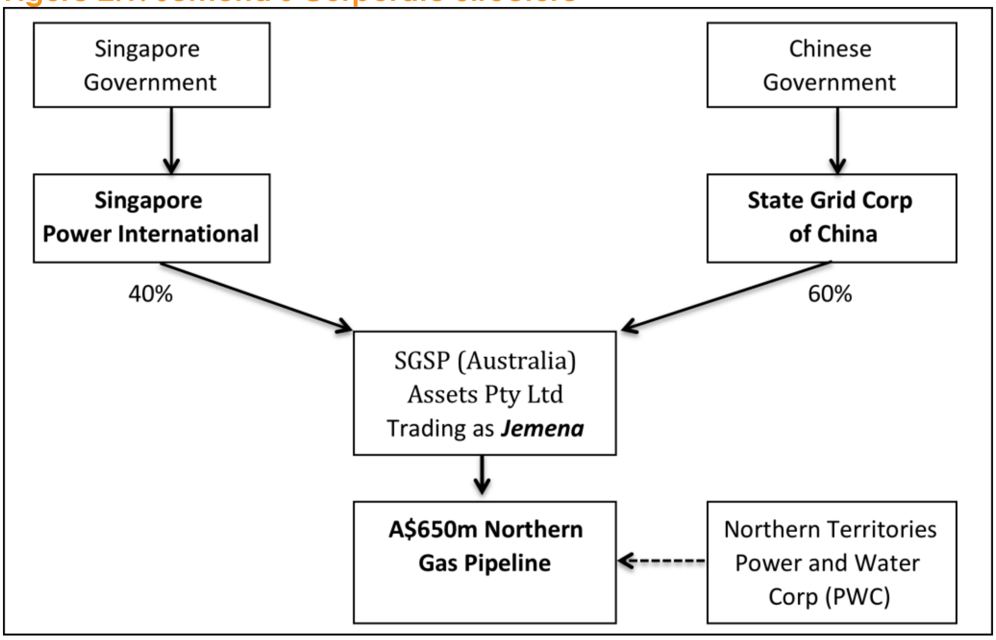
2. Jemena

2.1 Ownership of Jemena

Jemena is the trading name of SGSP (Australia) Assets Pty Ltd. On the Jemena website it is these accounts to which you are referred when seeking annual reports. SGSP (Australia) Assets Pty Ltd is the ultimate Australian parent of the group.

Jemena is owned 60% by the State Grid Corporation of China and 40% by Singapore Power International Pte Ltd – Figure 2.1.

Figure 2.1: Jemena's Corporate Structure



Effectively, the Chinese government owns 60% and the Singapore Government 40% of Jemena. Jemena is not a public company it is a government corporation.

2.2 Operating Businesses of Jemena

The group operates in Electricity Distribution, Gas Distribution, Gas Transmission, a small Water distribution business and a Services business.[8]

Gas transmission is the transport of gas through large capacity pipes principally from production fields to places of consumption. Gas distribution is the extensive pipe (mainly smaller capacity) network that takes the gas to the consumer premises.

[8] Taken from the 2015 Annual Report of SGSP (Australia) Assets Pty Ltd

Summary of the Operating Businesses of Jemena

Jemena operates in natural monopoly businesses. They are high capital intensity, high margin and return businesses. The NEGI is a gas transmission pipe. It fits in to the gas transmission and water distribution business. This division accounts for 12% of group revenue and 17% of group EBIT. For a divisional breakup of Jemena see appendix A.

2.3 Directors of Jemena

The board comprises of the following members:

- Mr Du Zhigang (Chairman)
- Mr Ruan Qiantu
- Ms Jeanne Cheng
- Mr Lim Howe Run
- Mr Paul John Adams (Managing Director)
- Mr Albert Yeuk Kuk Tse
- Mr Nicholas Greiner
- Ms Lena Yue Joo Chia

The board has put in place political connections with Mr Nicholas Greiner, former NSW State Premier, on the board. Mr Greiner is a senior member of the Liberal Party.

2.4 Financial Overview of Jemena

Jemena is a large business with annual revenues of $1.8 billion and a healthy net profit in 2015 of A$338m. Jemena has the financial backing to fund the NEGI.

Jemena has quite high debt levels with net debt standing at $5.4 billion and debt to equity levels of 158.7%. Net interest coverage is sound at 2.8x earnings before interest and tax (EBIT), and gross interest cover is 3.6x (against earnings before interest, tax, depreciation and amortization (EBITDA)). Funding should not be an issue as Jemena has stable predictable cash flows and the backing of two sovereign nations. The company earns high profit margins of 42.7%

Figure 2.2: Jemena's 2015 Profit (Year ended December)

	2015
Revenue	**1768.5**
EBITDA	987.5
Depreciation	-232.3
EBITA	**755.2**
Amortisation of Goodwill	0.0
Earnings Before Interest & Tax (EBIT)	755.2
Net Interest	-271.6
Profit Before Tax (PBT)	483.6
Tax	-144.8
Minorities	0.0
Net Profit After Tax	**338.8**
Significant Items	0.0
Reported Net Profit After Tax	**338.8**
Tax Rate	30%

$800m of convertible instruments is classified in the accounts as debt (see note 22b of the 2015 accounts). It is arguable whether these securities have debt or equity characteristics.

Figure 2.3: Jemena's 2015 Gearing and Interest Cover (Year ended December)

Gearing	2015	
Net Debt	5385.0	($m)
Shareholders Funds	3392.9	($m)
Net Debt / Equity	**158.7**	**%**
EBIT/Interest	2.8	x
EBITDA/Interest	3.6	x

Source: 2015 Annual Report of SGSP (Australia) Assets Pty Ltd, Author's calculations

2.5 Tax Position of Jemena

No income tax has been paid by Jemena in the last four years to 31 December 2015.

There is a nil balance in their franking account for each of the last 4 years.

They have large deferred tax expenses amounting to all of their total income tax expense in every year since 2012. Tax losses carried forward from 2012 were $148m. Tax losses appear to be the result of up-front or accelerated deductions for spend on property, plant and equipment.

Tax losses have been used up by the end of 2015.

In 2015 Jemena have a current year tax expense of $65.5m.[9] Some tax should be paid in 2016.

In 2015 Jemena's shareholders re structured their investment in the company. They converted their Trust loans into $3.2 billion of shares and an $800m convertible note (see note 22b of the 2015 Jemena accounts). The $800m of convertible instruments is classified in the accounts as debt. It is arguable whether these securities have debt or equity characteristics.

A common way of tax avoidance is for a parent company to charge high non-commercial interest rates on debt. This has the effect of reducing the profit before tax of a corporation and transferring that wealth to the parent company or intermediaries that may be located in lower tax jurisdictions.

Jemena's convertible notes are a debt instrument according to their accounts. The rate charged on these notes is not commercial. At 10.25% it is far above a commercial borrowing rate for a company such as Jemena. APA Group (APA), a similar company operating pipelines, paid an interest rate of 4.97% in 2015. In our opinion this is a method of transferring wealth generated by Jemena to the parent governments (those of Singapore and China) and reduce Australian Income tax costs.

[9] Current year tax expense from note 9, SGSP (Australia) Assets Pty. Ltd

3. Competitive Environment for Gas Transmission

The NEGI operates a natural monopoly. In economics the tendency is for natural monopolies to maximize their profits by charging as much as they can without affecting volumes. This results in the bulk of the economic benefits of the entire supply chain flowing to the monopoly service provider.

The NEGI, despite being a monopoly, operates in a totally unregulated environment. It can charge a non-commercial rate.

Note 5 on page 30 of the Jemena 2015 Annual report states:

> *(iii) Gas transmission and water distribution*
> The gas transmission and water distribution segment transports gas and water and earns revenue from these services at contracted rates negotiated on arm's length terms.

The non-regulation of a monopoly business is unusual even in the Australian context. Jemena's other monopoly businesses, such as electricity and gas distribution have regulated pricing regimes.

The dangers of such market power were eloquently delineated by Rod Sims, Chairman of the Australian Competition and Consumer Commission (ACCC), in a recent speech:

> *"Second, therefore, we also have to ensure that regulation, or the threat of regulation, is effective as it applies to natural monopolies like gas transmission pipelines. This currently does not seem to be the case." "Likely ineffective regulation of gas transmission pipelines is of particular concern because monopoly pricing can lead to inefficient downstream investment decisions and can limit investment in upstream exploration…"*[10]

This also illustrates the importance of gas transmission and transport costs.

The awarding of the NEGI contract to Jemena was an interesting decision by the Northern Territory government. In essence an Australian government has handed the governments of Singapore and China an unregulated natural monopoly for the transport of gas between the Northern Territory and Queensland. It is to these governments that the bulk of the natural wealth of the Northern Territory gas industry will accrue if the pipeline should go ahead.

[10] http://www.accc.gov.au/media-release/chairman-says-difficult-times-for-the-changing-gas-market

4. Gas Demand/Supply Dynamics

Introduction

It is reasonably widely accepted that the global LNG market is over supplied. What is not widely acknowledged is the over estimation of future demand that has occurred in the market. The effects of the global gas glut will have broad reaching consequences on how gas is priced and which gas provinces will survive the downturn. Stranded assets are inevitable, with the US$70bn of Gladstone Island LNG developments likely candidates on the evidence to-date.

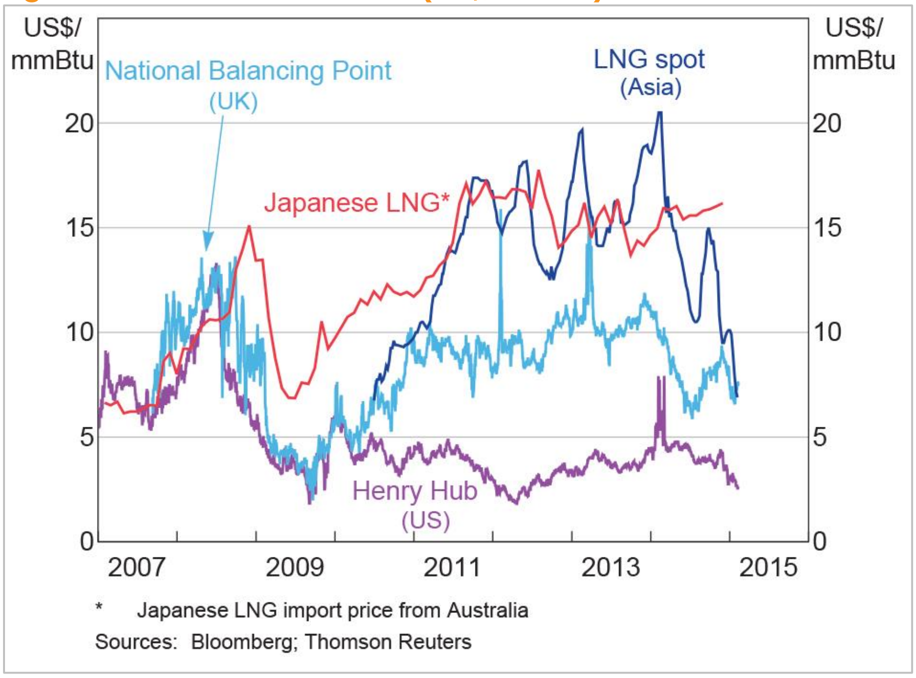
4.1 The Increase in Supply

In March 2011, the Great East Japan earthquake set off a chain of events that impacted dramatically on the global trade in LNG. The Fukushima nuclear accident and subsequent shutdown of the Nuclear power generating capacity of Japan left Japan short of electricity. It turned to LNG, as well as coal and oil, to fill the gap. Japan needed an additional 20 Mtpa of LNG equivalent to 8% of the global LNG demand. Japan managed to procure additional supplies of LNG by borrowing supplies from other consumer countries, including South Korea, and by increasing supply from producer countries such as Qatar.[11]

The global shortage the Great East Japan earthquake induced combined with strong demand growth out of China and high oil prices to put extreme upward pressure on Global gas prices over 2011-2014.[12]

It was these high gas prices combined with the expectations for continued strong demand growth from the rapidly developing Chinese economy that stimulated a rash of new LNG projects around the world.

Figure 4.1: Natural Gas Prices (US$/MMBtu)



Source: Bloomberg, Thomson Reuters

[11] http://aperc.ieej.or.jp/file/2015/9/28/150916_METI_Minister_Yoichi_Miyazawa_LNG_Conference.pdf page 3
[12] http://www.rba.gov.au/publications/bulletin/2015/mar/pdf/bu-0315-4.pdf

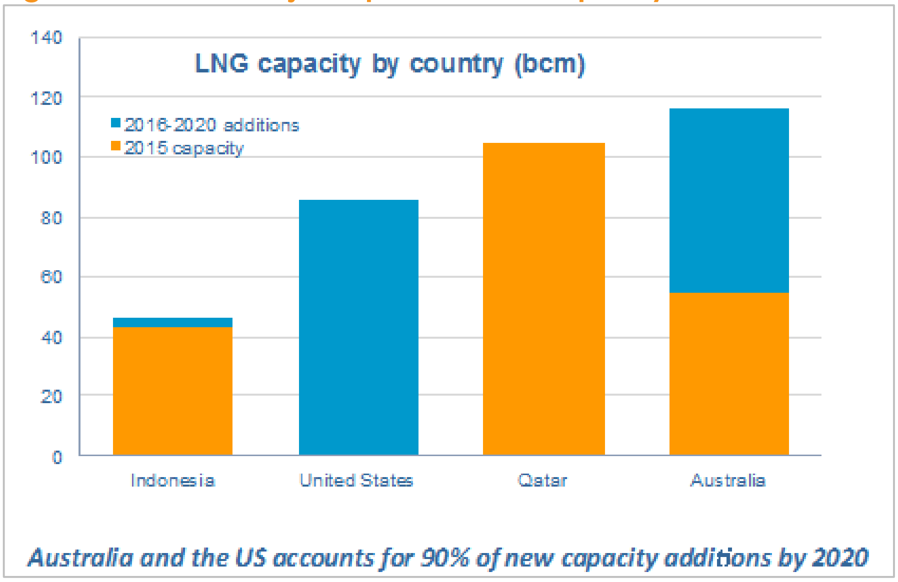
The global gas industry closed the 2015 year in a glut with total nameplate liquefaction capacity of 308Mt outstripping import demand for LNG of 245Mt by 26%.

Global LNG capacity is set to expand rapidly in the 2015-2020 period from projects that are fully committed and either already started, are in commissioning or under construction.

Global LNG liquefaction capacity is expected to reach around 400Mtpa, an increase of 30% from 2015. Approximately 92Mtpa of new capacity will be introduced to the global market between 2015 and 2020.[13]

The two countries globally where the bulk of the capacity is being installed are Australia and the US.

Figure 4.2: LNG – Major Exporters and Capacity Additions[14]



Source: IEA, April 2016

Figure 4.3: East Coast Australian CSG to LNG Projects[15]

	Equity Investors	*Nameplate Capacity Mtpa*	*First LNG*
Queensland Curtis LNG (QCLNG)	BG Group (73.8 per cent) CNOOC (25 per cent), Tokyo Gas (1.3 per cent)	8.5	Q4 2014
Gladstone LNG (GLNG)	Santos (30 per cent) Petronas (27.5 per cent) Kogas (15 per cent)	7.8	Q3 2015
Asia Pacific LNG (APLNG)	Origin (37.5 per cent) ConocoPhillips (37.5 per cent) Sinopec (25 per cent)	9	Q4 2015

Source: Department of Industry, Innovation and Science, 2015

[13] Page 79 Gas Market Report 2015 – The Office of the Chief Economist
[14] Is the global energy system at an inflection point – International Energy Agency April 2016
[15] Table sourced from Gas Market Report 2015 – the Office of the Chief Economist page 38

On the East Coast of Australia the high cost CSG fields in Queensland have been opened up to supply the three LNG export facilities. These facilities will also source gas from the Cooper and Eromanga basins in South Australia and the Bass Strait gas fields off the coast of Victoria. They had hoped to open up CSG fields in New South Wales (NSW) however these plans have been thwarted totally at Gloucester with AGL Energy withdrawing and relinquishing the Petroleum Exploration License (PEL). In the Northern Rivers of NSW, Metgasco was stopped by protesters, and at Narrabri Santos is years behind its development schedule due to continued environmental breaches, protests and downgrades to reserves.

In addition to the three east coast projects detailed in Figure 4.3, in Western Australia there have been major developments in Offshore LNG with the Gorgon, Prelude Floating LNG and Wheatstone projects offering a total combined capacity expansion of 28.1Mt.

Gorgon is a massive LNG project of 15.6Mtpa. It shipped its first LNG cargo on 20 March 2016. It is owned by Chevron (47.3%), Exxon Mobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (0.417%).[16]

Figure 4.4: Western and Northern Australian LNG Capacity (Existing and Proposed)

	Capacity Mtpa	Start-up Year
Western Market		
North West Shelf	16.3	1989
Pluto	4.3	2012
Gorgon	15.6	2016
Wheatstone	8.9	2017
Prelude Floating LNG	3.6	2017
Northern Market		
Darwin LNG	3.7	2006
Ichthys	8.9	2017
Total Producing	24.3	
Total Expansion Planned	37.0	

Source: OCE April 2016, Author calculations

The Gorgon project is emblematic of the cost and time line blow outs that plagued many of the LNG projects recently constructed in Australia. Originally slated to cost US$37 billion and delivering gas in early 2015 ended up costing around US$54 billion and did not ship its first cargo until March 2016.[17] The Cost overruns are not surprising given that there is a limited pool of expertise in building LNG facilities. This limited talent base was stretched to the extreme by the concurrent building of multiple plants in both Australia and the USA.

Wheatstone is Chevron's smaller project of 8.9Mtpa on the north west shelf. It has approval to expand to an even bigger project than Gorgon at 25Mtpa. Chevron is targeting the end of 2016 to ship its first gas from Wheatstone. Wheatstone is owned by Chevron (64.14%), Kuwait Foreign Petroleum Exploration Company (KUFPEC) (13.4%), Woodside Petroleum Limited (13%), and Kyushu Electric Power Company (1.46%), together with PE Wheatstone Pty Ltd, part owned by TEPCO (8%). [18]

The Prelude Floating LNG plant on the Browse basin is the smallest new project with annual LNG production of 3.6Mtpa. It is operated by Shell (67.5%) in partnership with Inpex (17.5%), Kogas (10%) and OPIC (5%).[19]

[16] https://www.chevron.com/stories/2016/Q1/First-Chevron-Gorgon-LNG-Cargo-Departs-for-Japan
[17] http://www.abc.net.au/news/2014-05-28/cost-of-labour-not-to-balme-for-escalating-gorgon-costs2c-new-/5481808
[18] https://www.chevron.com/-/media/chevron/projects/documents/fact-sheet-wheatstone-project-overview.pdf
[19] http://www.shell.com.au/aboutshell/who-we-are/shell-au/operations/upstream/prelude.html

In the Northern Territory, the Ichthys project has a total capacity of 8.9Mt. First gas is not expected until September 2017. The Japanese oil and gas company INPEX is the operator of the project with and interest of (62.2%), Total (30%), CPC (2.625%), Tokyo Gas (1.575%), Osaka Gas (1.2%), Kansai Electric Power (1.2%), Chubu Electric Power (0.735%) and Toho Gas (0.42%).[20]

All up the total increase in production forecast for Australia is 62Mt over the five years to 2020.[21]

North America

In the USA the "shale gas revolution" has led to excess production of gas and very low domestic prices versus the north Asian price. The US market has until very recently been a wholly domestic market. With low prices in the US, a political imperative to diversify sources of gas supply in Europe and at the time large unsatisfied demand from Asia, the export market was seen as a major new commercial opportunity. As with Australia, a rash of new export projects were all committed at the same time.

The total increase in capacity out of the LNG projects currently under construction in the USA is 62.7Mtpa – Figure 4.5.

Figure 4.5: US LNG Capacity Currently Under Construction

Project	*First LNG*	*Capacity Mtpa*
Sabine Pass	2016	22.5
Cove Point	2017	5.3
Cameron	2018	12.0
Freeport	2018	13.9
Corpus Christi	2019	9.0
Total		62.7

Notes: A sixth train at Sabine Pass and a third train at Corpus Christi are planned and would take the total to 71.7 Mtpa

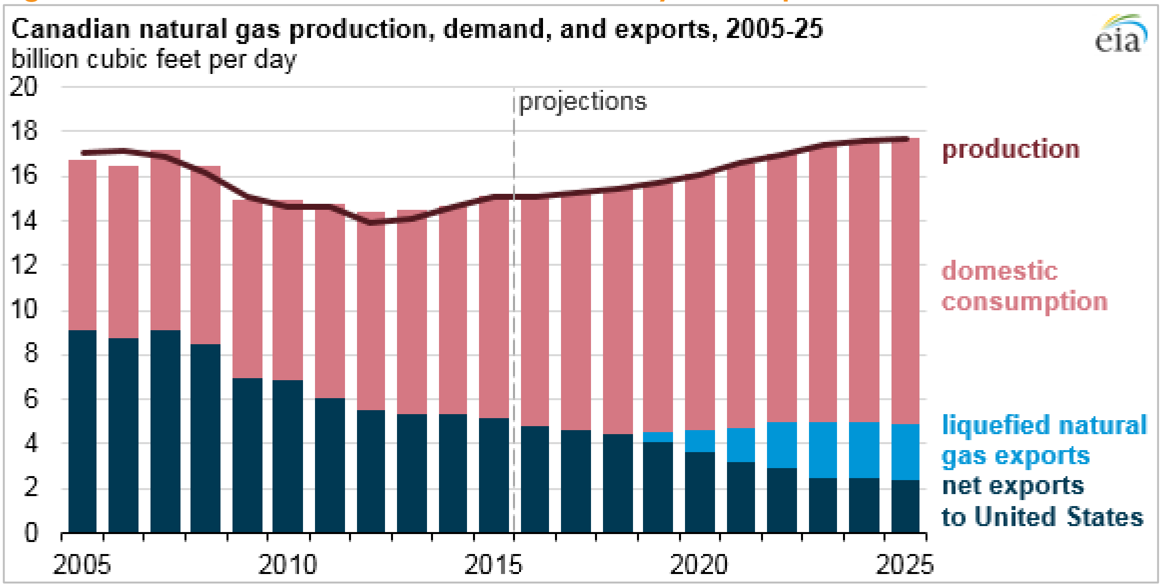
Source: OCE, April 2016, page 43

Canada

With America's growing domestic gas production, this has resulted in a progress decline of exports of pipeline gas from Canada to America over the last decade from a high of 10.6Bcf/d in 2007 to 7.4Bcf/d in 2014. The Canadian National Energy Board projects that by 2040 Canadian net gas exports to America will cease. [22]

[20] http://www.inpex.co.jp/english/ichthys/
[21] Gas Market Report 2015 – the Office of the Chief Economist page 79
[22] http://www.eia.gov/todayinenergy/detail.cfm?id=25972&src=email

Figure 4.6: Canadian Gas Production and Likely LNG Exports



Source: US Energy Information Administration, based on Canada's National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, 26 April, 2016.

4.2 The Demand Puzzle

The east coast gas market has undergone a rapid transformation over the last two years. Historically, the east coast Australian gas market has been a domestic market with prices reasonably stable at around $3-4/GJ. The advent of the building of 3 large LNG export plants at Gladstone has transformed the market. The first plant to export was the BG Group Queensland Curtis LNG (QCLNG) which shipped its first cargo in late 2014.

By 2020 the market will have been transformed with exports predicted by the Australian Energy Market Operator (AEMO) to account for 74% the total Australian gas production.[23]

Figure 4.7: Total Australian annual gas consumption by sector

Sector	2015[2]	2020	2035
Residential and commercial	185.5 PJ	185.1PJ	200.9 PJ
Industrial	294.3 PJ	261.9 PJ	267.4 PJ
Gas Power Generation (GPG)	175.0 PJ	69.3 PJ	184.5 PJ
LNG	353.8 PJ	1444.3 PJ	1431.3 PJ
Total	**1008.6 PJ**	**1960.7 PJ**	**2084.1 PJ**

Source: AEMO 2015

4.2.1 Domestic Demand

[23] National Gas Forecasting Report 2015 page 3

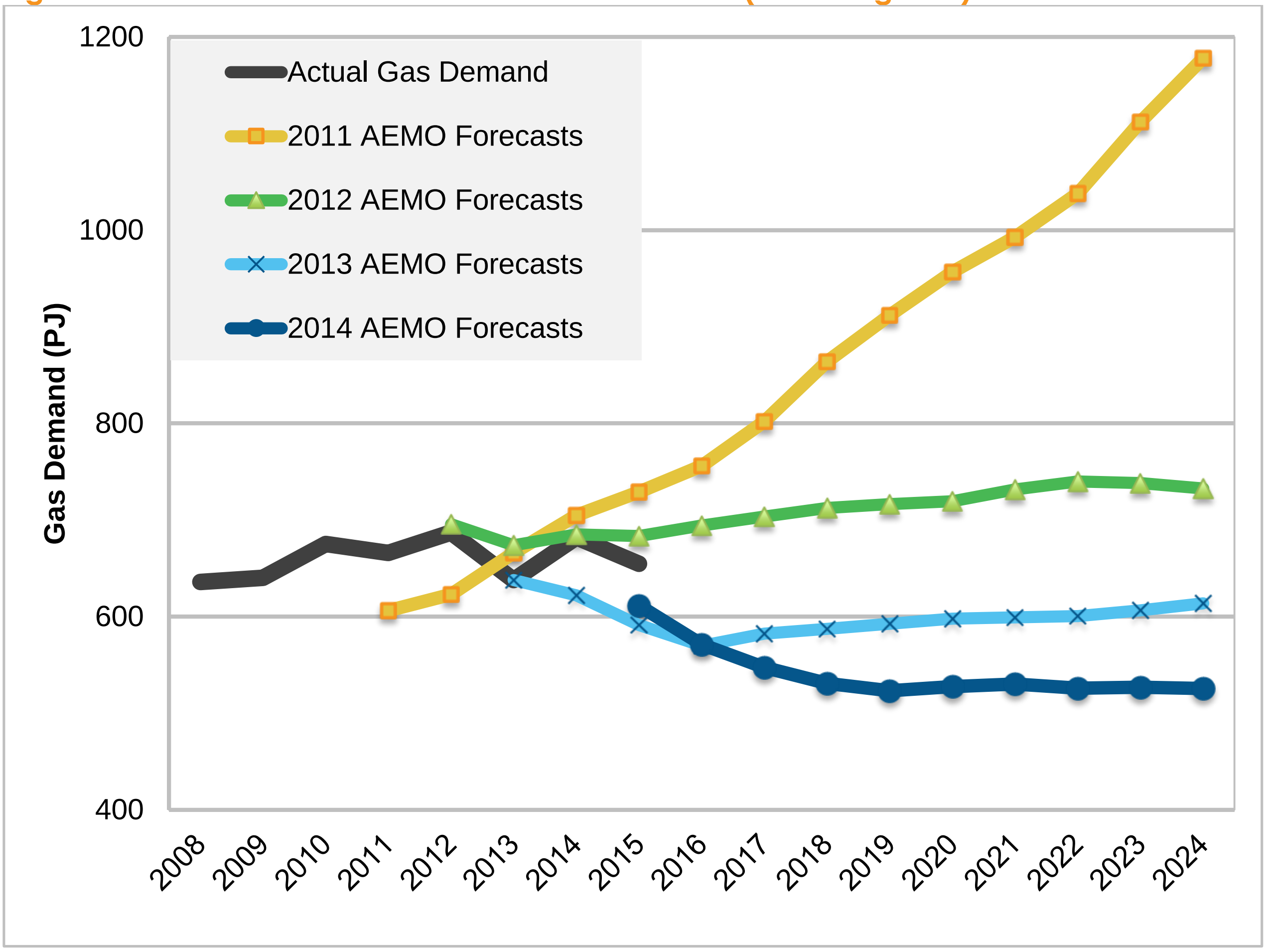
Domestic gas and electricity demand forecasts are officially done by the AEMO. This semi government body is 60% owned by government and 40% by industry.[24]

The AEMO has persistently over forecast demand for electricity[25] and gas.[26] The large forecasting errors in Gas lead to claims of East Coast Gas Shortages being made that were quite simply incorrect. The entirely predictable price elasticity of demand, the effects of energy efficiency and fuel substitution – all of which were under estimated by AEMO, saw demand for gas fall, directionally opposite to the dramatic rise that has been forecast by the AEMO.

Figure 4.6 shows the large downgrades in AEMO forecasts for east coast Australian gas demand. The blue line is the actual gas demand figures. The red, green, purple and light blue lines are the large downgrades in demand undertaken by AEMO forecasters in the successive years from 2011 to 2014.

Domestic gas demand fell 4.0% year on year in 2015 to 654.8 PJ.[27] AEMO forecasts for 2015 have been marginally raised from the 2014 outlook from a -0.8% pa decrease out to 2035 to a -0.2% pa decrease.[28]

Figure 4.8: AEMO East Coast Gas Demand Forecasts (Excluding LNG)



Source: Bruce Robertson 2015

[24] http://www.aemo.com.au/About-AEMO/Membership
[25] http://www.smh.com.au/business/how-dodgy-forecasts-inflate-your-energy-bill-20120727-22xxf.html
[26] http://www.smh.com.au/business/mining-and-resources/gas-demand-forecasts-are-completely-fracked-20140226-33hrj.html
[27] the 654.8 figure added up from Table 1 on page 3 of 2015 National Gas Forecasting report - AEMO
[28] 657.5 is the 2030 forecast in the 2015 National Gas Forecasting Report - AEMO using -0.2%pa growth rate in table7 on page 16

Even with this revision upwards the 2030 forecast made in 2011 is a massive 58.7% higher than the forecast made in 2015.

Infrastructure building for both gas and electricity is based on the long term forecasts for demand. The AEMO's grossly inflated forecasts for electricity[29] fed into their gas forecasts. In the domestic market, gas used for electric power generation makes up 27% of demand, with the remainder being used by the industrial sector (45%) and the residential and commercial sector (28%).[30] The inflated forecasts for electricity demand led to the gas-fired power generation AEMO forecasts being grossly inflated. Compounding the error the AEMO failed to take account of the rising prices for gas making gas powered generation less competitive. The high gas prices has led to some gas fired power generators being shut[31] well before their economic life had expired.

The over-forecasting of demand in 2011 to 2014 has led to large over investment in infrastructure and forced domestic gas prices well above comparable levels overseas.

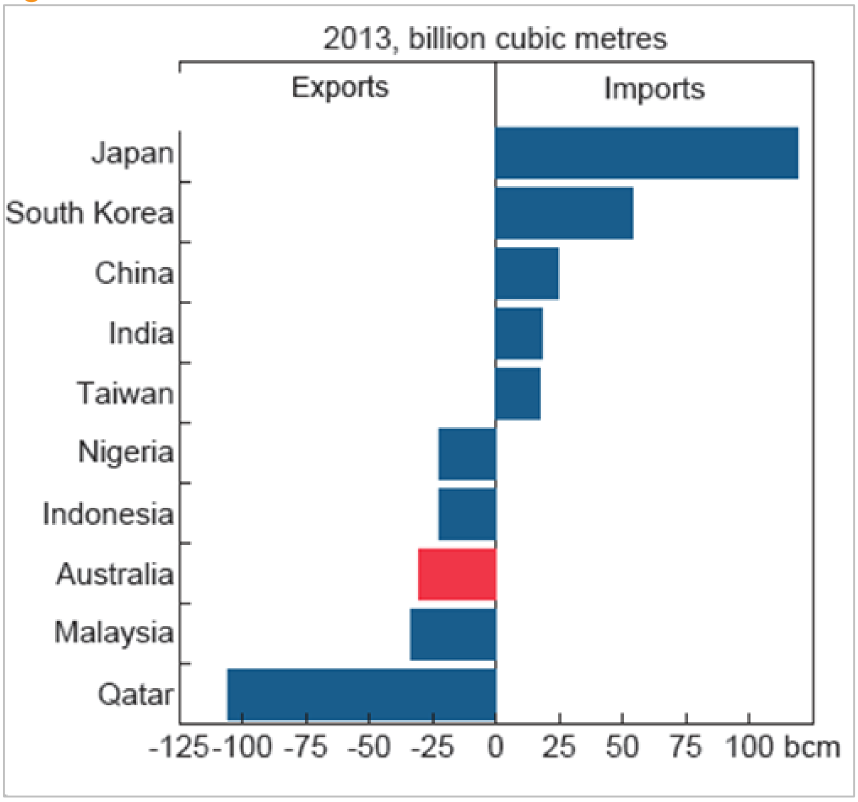
4.2.2 International Demand [32]

International supply and demand dynamics need to take into account all forms of natural gas not just LNG. When looked at from this perspective it can be seen that Russia is the largest net exporter and the second largest producer of natural gas.

In LNG Qatar is the largest exporter currently. With the large projects outlined above Australia is expected to be a larger exporter of LNG than Qatar by 2018.

Australia's LNG industry is founded on the large demand for LNG from Asia. Our three largest export markets are Japan, Korea and China.[33]

Figure 4.9: International LNG Trade



Source: BP (2014), RBA

[29] http://www.smh.com.au/business/how-dodgy-forecasts-inflate-your-energy-bill-20120727-22xxf.html
[30] page 30 Gas Market Report 2015 Office of the Chief Economist
[31] http://www.businessspectator.com.au/article/2014/2/6/energy-markets/swanbank-shut-down-swan-song-gas
[32] http://www.iea.org/publications/freepublications/publication/KeyWorld_Statistics_2015.pdf Page 13
[33] Australia and the Global LNG Market – Reserve Bank Bulletin March 2015

Figure 4.10: Producers, Net Exporters and Net Importers of Natural Gas (2014)

Producers	bcm	% of world total
United States	730	20.7
Russian Federation	644	18.3
Islamic Rep. of Iran	169	4.8
Canada	162	4.6
Qatar	160	4.5
People's Rep. of China	130	3.7
Norway	113	3.2
Turkmenistan	87	2.5
Saudi Arabia	84	2.4
Algeria	80	2.3
Rest of the world	1 165	33.0
World	**3 524**	**100.0**

2014 provisional data

Net exporters	bcm
Russian Federation	179
Qatar	119
Norway	107
Turkmenistan	57
Canada	56
Algeria	45
Indonesia	34
Netherlands	30
Nigeria	25
Australia	25
Others	159
Total	**836**

2014 provisional data

Net importers	bcm
Japan	128
Germany	68
Italy	56
People's Rep. of China	50
Korea	49
Turkey	48
France	38
United States	33
United Kingdom	32
Spain	28
Others	286
Total	**816**

2014 provisional data

1. *Net exports and net imports include pipeline gas and LNG.*

Source: IEA 2015

4.2.3 Outlook for Major LNG Importing Nations

The official forecaster for LNG demand in Australia is the Office of the Chief Economist (OCE). Like the AEMO this government body appears to suffer from an over enthusiasm that is not matched by what is occurring in the real world. The OCE has stated:

> *"Global LNG demand is expected to grow strongly to 2020 to approximately 457bcm (336 Mt), an annual increase of 5.9% from 2014 …. This growth is led by China, the rest of Asia and Europe, offset by falling demand in Japan. Demand growth has softened recently but the prospects remain positive overall."*[34]

In numbers just released by the International Group of Liquefied Natural Gas Importers (GIIGNL) global LNG trade grew by 2.5% in 2015 under half the annual growth rate projected out to 2020 by the Office of the Chief Economist.[35]

[34] Gas Markets 2015- Office of the Chief Economist page 80
[35] The LNG Industry – GIIGNL Annual Report – 2016 Edition

The key markets for Australian LNG producers are in North Asia. Importantly, LNG demand in North Asia contracted by 1.7% (-3MT) in 2015.

To examine the proposition of growing demand out to 2030 outlined by the OCE we must examine each of the major markets in turn. The major markets that will affect demand are the largest export market – Japan and the fastest growing export market China.

i) Japan

In examining the demand to come out of Japan it is vitally important to examine how the Japanese see their LNG demand developing.

In a Keynote Speech at the LNG Producer-Consumer Conference in Tokyo in September 2015 Yoichi Miyazawa, Minister of Economy, Trade and Industry (METI) stated:

> *"On the consumer side, let us first look at quantitative changes in the case of Japan. In July, the Government of Japan formulated the Long-Term "Energy Mix" towards 2030. The share of LNG in the power generation mix will fall from over 40% today to around 27%. Last month, Sendai Nuclear Power Plant restarted after the Nuclear Regulation Authority confirmed its conformity with the new and stringent regulatory requirements. This event ended the more than two years of zero nuclear period. However, Japan will continue to be the largest importer of LNG in the world."*[36]

It is not just the restarting of some of the 49GW of stranded nuclear capacity across Japan that will diminish Japanese LNG import demand into the future. The energy crisis that beset Japan following the nuclear meltdown at Fukushima, and subsequent closure of the Japanese nuclear industry, changed power consumption patterns in Japan. Japanese consumers learnt to use less power, with electricity consumption across Japan having declined 12% since 2010, a clear decoupling of energy demand from economic activity. Once consumer behaviour changes it does not tend to change back to old patterns.

Combining with a change in consumption patterns new technology in energy saving appliances and two generations of energy saving lighting (compact fluorescent globes and LED lighting) have permanently reduced demand.

Overlying these two trends is the rise of solar power. Solar power is now approaching grid competitiveness with fossil fuels and further significant cost reductions are forecast as solar and battery technologies continue to be refined. Japan exited 2015 with a total installed solar generation base of 25GW, and installations have been added at a rate of 8-10GW annually in 2013-2015. A total of 79GW of solar project proposals have been approved across Japan since 2012.

In 2014 Japan imported a record 89 MT of gas.

Japanese imports fell in 2015 by 4.7% to 85Mt.[37]

According to Eclipse Energy, the analytics unit of Platts:

> *"Restart of nuclear reactors in Japan, growing renewable sources of energy and a slow economy are expected to push down the country's LNG consumption by*

[36]http://aperc.ieej.or.jp/file/2015/9/28/150916_METI_Minister_Yoichi_Miyazawa_LNG_Conference.pdf
[37]http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2016_annual_report.pdf

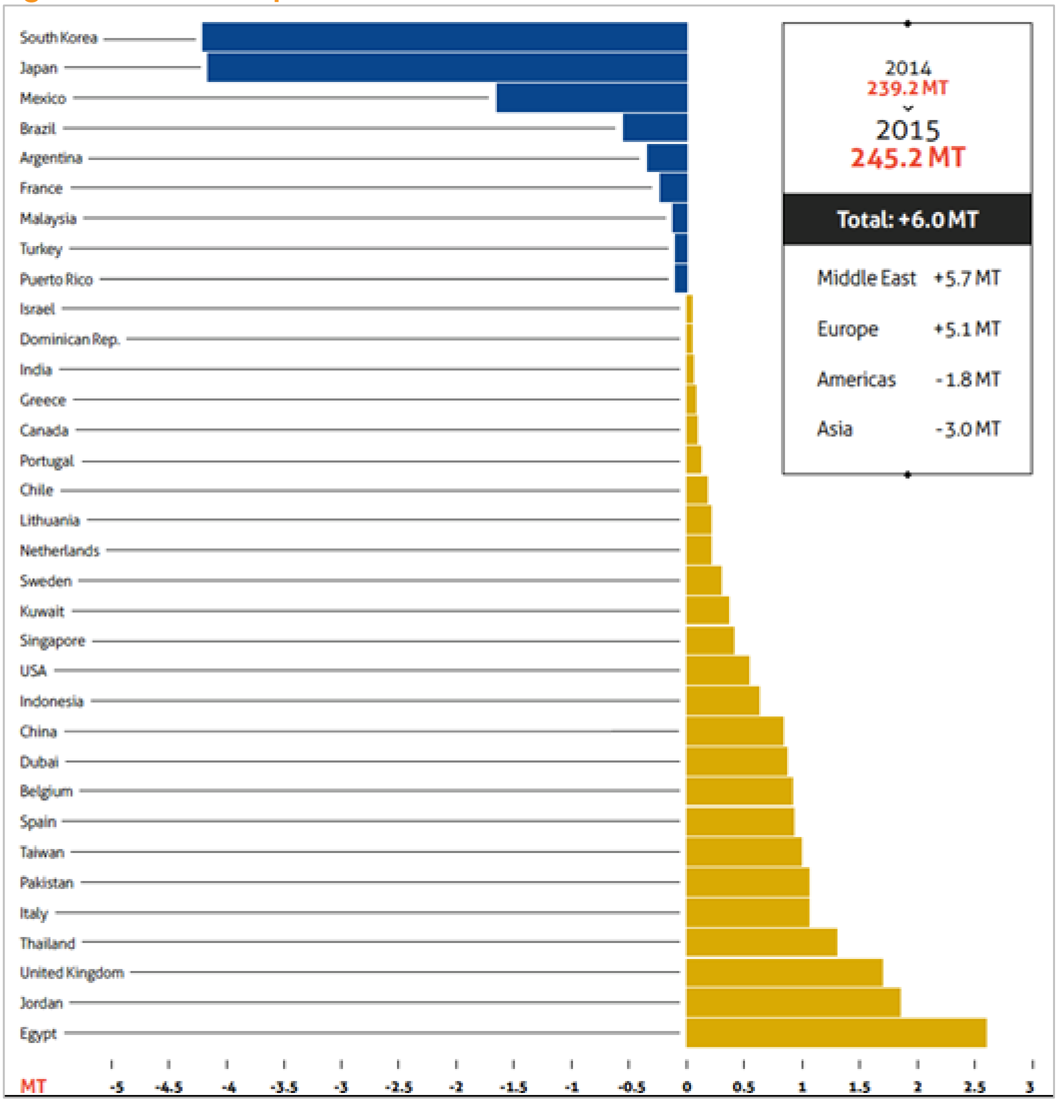
2020 by as much as 10.5% from 2014 levels" [38]

In September 2015 METI was quoted as forecasting a significant decline in Japanese LNG imports over the next fifteen years:

> *"Japan, the world's largest LNG buyer, will see imports fall to 62mtpa by 2030 as gains in fuel efficiency and the greater use of coal and renewable energy whittle down gas demand, the country's energy minister said on 16 September."* [39]

The 62Mtpa quoted here by the Japanese Energy Minister as the expected level of LNG imports in 2030 is 28% below 2014 levels. This is a quantum decline in demand from our largest LNG export market. The OCE is likewise now belatedly acknowledging the Japanese LNG import market is in structural decline. In April 2016 the OCE forecast a 2.7% annual decline to just 72Mtpa by 2021.

Figure 4.11: LNG Imports 2015 Versus 2014



Source: The LNG Industry, GIIGNL Annual Report, 2016 Edition

[38] http://www.platts.com/latest-news/natural-gas/tokyo/japan-lng-demand-expected-to-fall-by-2020-on-27051779
[39] http://www.icis.com/resources/news/2015/09/16/9924240/japan-lng-imports-to-drop-to-62mtpa-by-2030-meti/

ii) South Korea

In South Korean demand for LNG is a similar if less dramatic picture to Japan. Demand from the power generation sector is expected to nearly halve to 9.5Mtpa by 2029 according to the Ministry of Trade Industry and Energy in December 2015.[40] Household and industrial use is expected to grow at a relatively strong rate of 2% pa.

Overall, demand is expected to fall 5% from 36.49Mt in 2014 to 34.65Mtpa in 2029. While details are limited, the 9% year on year decline in Korean LNG imports in 2015 was a substantial negative surprise to the global LNG market, particularly after Korea increased its coal tax to US$21/t effective July 2015 and introduced a carbon price in January 2015, both measures designed to reduce coal's cost competitiveness vs LNG and renewable energy.

iii) China

Clearly with demand forecast to continue falling in both Korea and Japan in the forecast period, the Office of the Chief Economist is relying on massive increases in demand for LNG out of China to support its large increases in forecast demand.

While domestic gas demand may well increase at a robust rate in China, it is a fundamental mistake to conflate this with a rise in demand for LNG. China has other sources of gas, principally piped gas from Russia, on which to rely on for increases in demand. China is also pursuing a domestic gas production expansion program.

In 2015 the Chinese economy grew by 6.9%, down marginally on 2014 growth rate of 7.3%. In the midst of this consistently high growth in economic activity, electricity consumption was up by only 0.3% in 2015 and thermal power generation actually fell by 2.7%.[41]

At the same time as thermal power production fell investment in renewable energy ramped up. The installed grid-connected wind power generation capacity was 145GW, up 31-32GW or 30% over 2015 alone.[42] The installed grid-connected solar power generation capacity was 43GW, an increase of 73.7% year on year.

Combined Solar Wind and Hydro power, truly renewable sources of energy, now account for 33% of installed electricity generating capacity in China.

The key point is not that we are seeing renewables replace thermal power immediately but that they are sending thermal power sources for electricity production into structural decline in the largest electricity market in the world at a time when China is continuing to report rapid economic development.

[40] http://uk.reuters.com/article/southkorea-gas-idUKL3N14H14720151228
[41] http://www.stats.gov.cn/english/PressRelease/201602/t20160229_1324019.html
[42] Global Wind Energy Council 2015 Global Wind Report – Annual Market Update.

4.3 The Outlook for Australian LNG Exports to China

We see five principal dynamics that will crimp demand for Australian LNG in China:

a) The rise of renewable energy

b) The growth of a domestic gas industry

c) Global geopolitics affecting energy security issues

d) Increased Russian supply

e) Fugitive emissions

4.3.1 The Rise of Renewable Energy

China is a centrally planned economy and the future demand for energy and its sources has been clearly delineated by the head of the world's biggest power provider, Chairman Liu Zhenya of China's State Grid Corporation. He recently told a US energy conference the ramp-up of renewable energy and ongoing integration of wind and solar were gathering pace:

> "*A fundamental solution [to address power needs and climate change] is to accelerate clean energy.*" *The eventual aim was* "*replacing coal and oil.*"

The rapid build-up of renewables can be deployed quickly and economically:

> "*Clean energy is competitive,*" *said Liu.* "*The only hurdle to overcome is mindset. There's no technical challenge at all*".[43]

4.3.2 The Growth of a Domestic Gas Industry

The centrally planned Chinese economy decided on the 15 March 2016 to increase the subsidy paid to domestic CSG producers by 50% from $0.79/GJ to $1.19/GJ.[44] The increase effective from 1 January 2016 was announced by the Peoples Republic of China as part of the country's 13th Five-Year-Plan.

This is a very large financial incentive to develop the domestic gas industry. The full implications of this large subsidy will only be seen in the fullness of time.

4.3.3 Global Geopolitics Affecting Energy Security Issues

China has reasonably clear strategic goals in the South China Sea.[45] These goals are currently creating national security issues with Japan, Vietnam, the Philippines and Malaysia. The significant offshore oil and gas resources could see the development of a

[43] http://www.smh.com.au/business/mining-and-resources/adani-is-just-not-going-to-happen-20160404-gnxwkl#ixzz45Bld5XGC

[44] http://www.rigzone.com/news/oil_gas/a/143555/China_Raises_Cash_Subsidy_for_CBM_Produced_Locally_by_50

[45] http://edition.cnn.com/2016/01/20/asia/vietnam-china-south-china-sea-oil-rig/

globally significant new gas basin.

China has a clear strategic imperative not to be reliant on the west for its energy needs. To this end it has fostered closer energy ties with the Russians.

4.3.4 Russia

Gazprom, the Russian oil and gas company, is the world's largest producer of gas. Russia is currently the largest supplier of gas to Europe. Following the Ukraine invasion, Europe is increasingly looking to diversify their gas supplies. As a result of these strategic reasons,[46] Russia is looking to increase its share of the Chinese gas market.

Gazprom has signed two massive pipeline deals with CNPC. CNPC is China's state-owned petroleum company and is one of the worlds leading integrated energy companies.

On 21 May 2014, Gazprom and CNPC signed a contract to supply gas from Russia via the eastern route, the so called Power of Siberian pipeline. The 30 year contract amount was 38bcm of gas per year (equivalent to 28Mtpa of LNG).

This contract was followed up with a second deal a year later. On 8 May 2015 Gazprom and CNPC signed a heads of agreement for a gas pipeline via the Western route (Power of Siberia-2 pipeline). Initially 30bcm a year (equivalent to 22Mtpa of LNG) are due to be delivered to China from Western Siberian fields.

These two deals are game changers for the global LNG industry. They are equivalent to 50Mtpa of cheap accessible gas. China was the growth market and all of that growth has been taken out by these two massive gas pipeline deals. Piped gas is inherently cheaper to produce than LNG as liquefaction of the gas is an expensive and energy intensive process.

4.3.5 Fugitive Emissions

Australia's lack of scientific analysis on the fugitive emissions relating to methane could materially jeopardize Australia's key LNG target markets. The lack of independence of the CSIRO research is well documented.[47,48] This could become a key strategic risk for Australia as countries like China continues to pursue ever more aggressive policies focused on energy security, pollution and climate change. If China realises the whole of chain emissions profile of LNG is materially higher than the Australian industry has portrayed, this could substantially undermine the relative merits of LNG versus cleaner alternatives of energy efficiency, hydro-electric, wind farm projects or distributed solar with storage. The Office of the Chief Economist China energy modelling makes it clear LNG comes at a higher dollar cost to China than alternatives, and we would therefore contend that China will be less willing to pay a higher cost if the expected emission benefits prove to be materially overstated.[49]

[46] http://www.platts.com/latest-news/natural-gas/london/russias-gazprom-makes-plans-to-increase-global-26371163
[47] https://www.thesaturdaypaper.com.au/news/environment/2015/12/12/coal-seam-gas-leaks-climate-debacle/14498388002741
[48] https://independentaustralia.net/environment/environment-display/condamine-fire-csiro-called-out-over-conflict-of-interest-with-gisera,8935
[49] http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Key-factors-affecting-changes-in-Chinas-demand-for-liquefied-natural-gas.asp

4.3.6 Chinese LNG demand Conclusion

With the technology changing the way we produce and consume energy the growth of Chinese imports of gas is far from assured. The Russian pipeline deals ensure that any growth in the market over the medium to longer term will be filled by piped gas not LNG.

4.4 The European Market

Around half of European gas is sourced from Russia and Norway via piped gas.

The invasion of the Ukraine by Russia in 2014 caused considerable fears for energy security in Europe and led the Europeans to look for alternative sources of supply.

The USA for its part was looking to develop its LNG export industry and so found a ready market in Europe.

The Russians and Norwegians are not going to give up market share. Russia is producing and exporting more gas into Europe, while Norway is looking to maintain volumes. This has led to a similar situation to the oil market as producers wrangle for market share and consumers enjoy very low prices.

Figure 4.12: EU Gas Prices Have Crashed Since US LNG Exports Commenced

Source: Bloomberg

As we have stated previously the key here is the inherent economics of gas. Pipeline gas is cheaper than LNG and in any price war the low cost producer wins. Tor Martin Anfinnsen, Statoil senior vice president for marketing, said in an interview:

> *"But if gas falls further, LNG would be priced out because pipeline-shippers Norway and Russia have lower costs,"*[50]

50 http://www.bloomberg.com/news/articles/2016-04-20/russia-and-norway-use-saudi-oil-strategy-in-europe-s-gas-market

While gas prices have collapsed in Europe, some forecasters are predicting large falls to come. Fitch Group Inc.'s BMI research has predicted that prices may slide 29% to as low as $2.86/mmBtu.[51] At these levels LNG will struggle to compete.

The LNG currently finding a market in Europe may look to the higher priced Asian markets to off load supply exacerbating the glut there.

4.5 Global Supply/Demand Summary

Globally the LNG market faces an unprecedented increase in supply with Global LNG capacity increasing by 30% over the period 2015- 2020 to 400Mt.

Out to 2030 demand is forecast to grow to 391Mt by the Office of the Chief Economist.[52]

Official government forecasts are for a long term glut in supply out to 2030.

The Official forecasts for demand are however too high.

Australia's largest 2 export markets, Japan and Korea, are expected to shrink out to 2030 according to those countries energy ministries. The great growth hope, China is seeing its demand satisfied by cheaper and strategically superior piped gas out of Russia and the growth in renewables.

It would seem that the Office of the Chief Economist's projections of growth in all of Australia's key LNG markets, is overly optimistic.

The Office of the Chief Economist states:

> *"We expect that the Global LNG market will have excess supply capacity at least to 2020 and likely beyond, leading to a prolonged period of lower gas prices. LNG suppliers will therefore face a challenging environment over the medium to longer term to 2030."*

We would view this as too optimistic. Our opinion is the Global LNG industry is in a demand crises, particularly acute in the markets that are critical to Australia, the north Asian markets.

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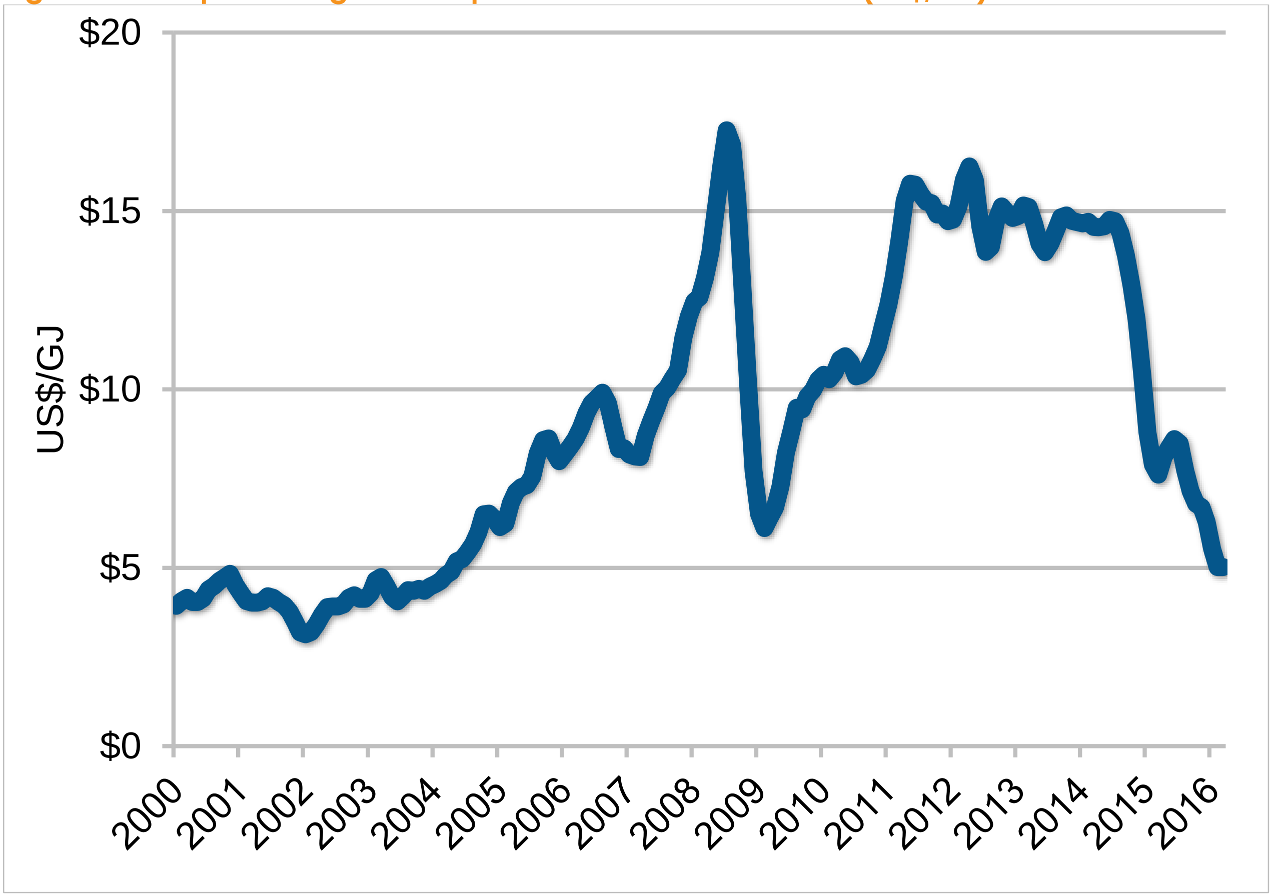
[51] http://www.bloomberg.com/news/articles/2016-04-20/russia-and-norway-use-saudi-oil-strategy-in-europe-s-gas-market
[52] Gas Market Report – Office of the Chief Economist page 85

4.6 Prices

Figure 4.13 Implied Long-Term Japanese Gas Contract Price (US$/GJ)



Source: ACCC, RBA, EIA and Authors Calculations

Most of Australia's LNG is currently sold on long term contracts which typically range from 15-20 years.[53] For historical reasons, the price on the contracts is set with reference to the Japanese Customs Cleared crude price (which is equivalent to Brent Crude prices). The reason behind this link is that when Japan first started importing LNG it was used in electricity generation. The principal competing fuel at that time was Oil.

Not all contracts are necessarily the same and according to the Reserve Bank of Australia:

"Long-term contract price arrangements can often be subject to periodic renegotiation (e.g. every three to five years). Renegotiations may occur due to bilateral agreement or can be triggered contractually by large oil price movements."[54]

With the recent extreme volatility in the oil price it is likely that many contracts are currently being renegotiated.

The changing global gas market, particularly with the USA moving from a large importer to a substantial exporter, will break the traditional way of pricing gas with reference to oil.

The US possesses a well-developed, transparent domestic spot gas market called the Henry Hub. Almost 80% of US LNG export volumes for projects currently under construction have

[53] Reserve Bank of Australia -Australia and the Global LNG market – March Quarter 2015 – Reserve Bank Bulletin page 36
[54] Reserve Bank of Australia - Australia and the Global LNG market – March Quarter 2015 – Reserve Bank Bulletin page 37

been contracted on pricing terms directly linked to the Henry Hub price or under some hybrid pricing arrangement including the Henry Hub.[55] The development of the US export market, combined with a glut in supply and limp demand, is likely to shift pricing away from Oil based contracts to more flexible contracts based on gas prices.

Many of these changes in contract arrangements have already been observed. In a speech given to an LNG conference in September 2015 Japanese Minister Yoichi Miyazawa stated:

> *"The first Conference was held three years ago. Since then, we have witnessed remarkable changes in the market. For example:*
>
> *(1) The share of spot transactions and short- and medium-term transactions has risen to 30% of worldwide LNG transactions.*
>
> *(2) More relaxed destination clause has provided new opportunities for buyers to resell LNG.*
>
> *(3) New gas-linked pricing in addition to conventional oil-linked pricing provides wider price-setting options.*
>
> *These changes lead to creation of "well functioning market" with more flexibility and liquidity, which brings merits to both producers and consumers."*[56]

This is a distinctly customer centric view, something that Australian commentators on the LNG industry are loathe to acknowledge.

Consumers are increasingly looking to "re-negotiate" contracts in the face of the massive glut in supply. Already India's Petronet LNG has managed to recast its contract with Qatar's Rasgas. The renegotiation cut prices in half over the 25 year contract, replacing the original prices with a more "dynamic pricing system". On March 9, 2016 China National Petroleum Corporation's chairman Wang Yilin said the company was aiming to change the way its LNG supply contract with Qatargas was priced.

Conditions for LNG producers have become far more competitive and difficult and will likely remain so out to 2030.

[55] https://www.eia.gov/todayinenergy/detail.cfm?id=23132
[56] http://aperc.ieej.or.jp/file/2015/9/28/150916_METI_Minister_Yoichi_Miyazawa_LNG_Conference.pdf

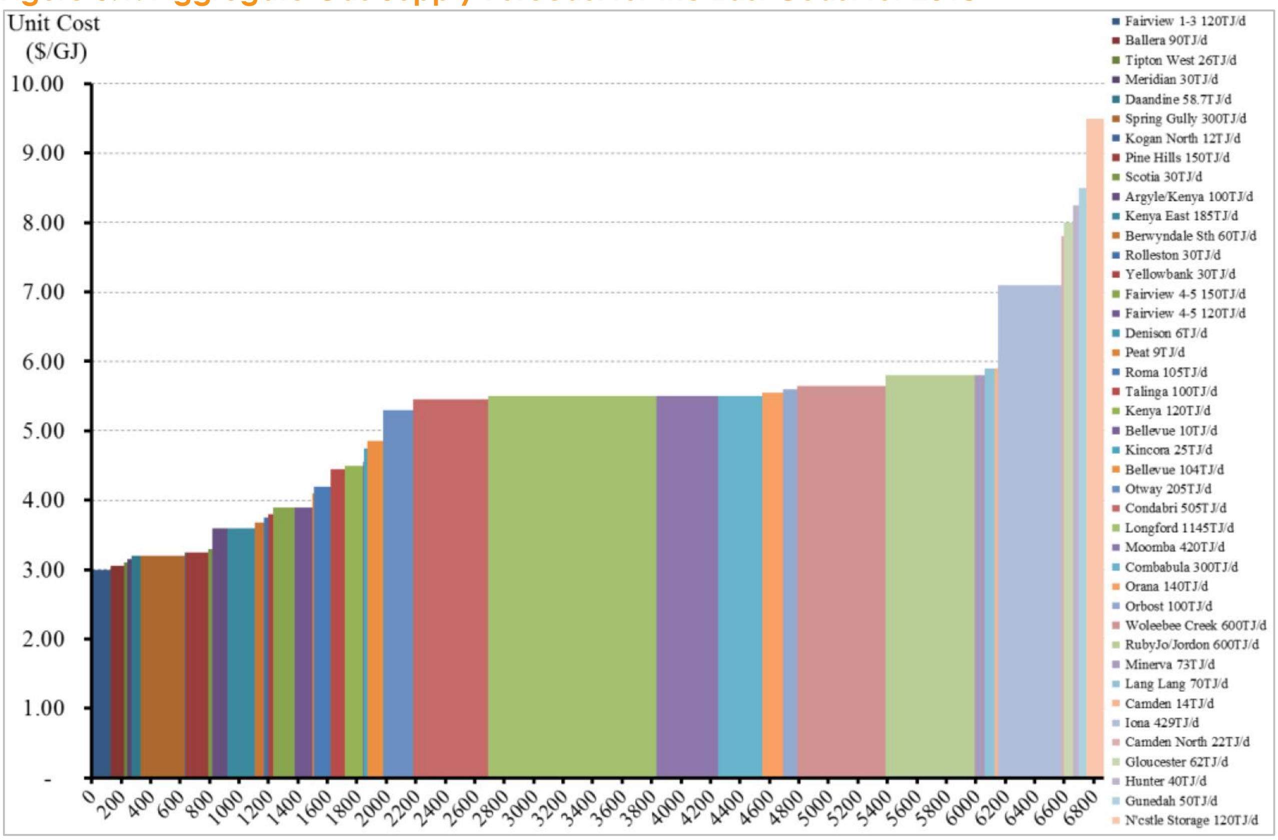
5. Economics of the East Coast Gas Market

Given that the changes in the global gas market are leading to the USA and Russia to becoming the two major competitors for Australian LNG it is useful to note that at present the Henry Hub (US spot price for gas) is around USD 2/GJ. Additionally, Russia is, as we have previously outlined, the globally low cost producer, particularly with the dramatic Russian Ruble depreciation over the last two years.

The East Coast Australian onshore gas fields are high cost fields in a global context. While prices were at historic highs this was not an issue as there were fat profit margins. With markets returning more to their long term norms the high cost nature of the onshore fields is starting to assert itself.

In a paper authored by AGL economists, Paul Simshauser and Tim Nelson,[57] arguing that the East Coast Gas market was facing a shortage, they let slip the production costs for every onshore and offshore gas field on the East Coast of Australia. The East Coast Gas shortage has been proven to be a myth however the graphic of well head costs remains a useful starting point to analyse the profitability of onshore gas in Eastern Australia.

Figure 5.1: Aggregate Gas Supply Forecast for the East Coast for 2018



Source: Solving for "x" – the New South Wales Gas Supply Cliff, Paul Simshauser, and Tim Nelson, March 2014

[57] *Solving for "x" – the New South Wales Gas Supply Cliff, Paul Simshauser and Tim Nelson, March 2014*

As can be seen in Figure 5.1 the bulk of East Coast gas production lies between A$5.50 and A$6.00 at the well head. Converting this at the current exchange rate of $0.76 gives production costs of US$4.18-4.56.

Added to this production cost is the cost of piping the gas to Gladstone. The gas fields reasonably close at Roma can use the Wallumbilla to Gladstone pipeline. According to AGL this costs a further A $0.96 /GJ or US$0.73/GJ.

Total costs for East Coast gas is therefore around US$4.91GJ to US$5.29GJ prior to liquefaction and shipping costs. This is for the fields close to Gladstone. For Moomba for example a further A$1.36 or US$1.03 must be added to take total costs to around US$5.94. Transport of gas over unregulated monopoly gas transmission pipes in Australia is not cheap.

These costs compare to a current US Henry Hub price of under US$2/GJ after piping the gas to the Hub.

The inescapable conclusion is that Australian East Coast Gas is globally high cost gas.

Using Reserve Bank of Australia methodology for determining the current Japanese contract price we get a price of around US$5.03/GJ. Whilst it must be acknowledged that every contract written is different it would appear that the majority of Australian East Coast Gas fields are currently loss making prior to taking into account shipping costs and liquefaction costs.

Taking into account shipping and liquefaction all of the east coast export market is currently in loss.

6. The Economics of the NEGI

Apart from the non-commercial agreement to transport excess contracted gas owned by the Northern Territory government owned Power and Water Commission, the NEGI has been unsuccessful in attracting other customers. So much so that it was downgraded in April 2016 from the small 14 inch pipe by one quarter to 12 inches.

The NEGI faces a very basic challenge – in today's low price environment it simply does not make sense to develop a very high stranded gas cost resource. In basic economic terms we are competing with piped gas out of Russia. Against this competitor the NEGI is attempting to facilitate the development of a high cost gas source, transport it half way across one of the largest countries in the world, take it through the expensive liquefaction process, ship it up to China and hope to compete!

Once the gas gets to Mt Isa if it is to use the existing pipe network it would cost a further A$3.25[58] or US$2.47 to transport it to Gladstone for liquefaction.

Unconventional gas in the Northern Territory is very high cost gas. According to analysts from Wood Mackenzie:

> *"While the NT is very early stage in terms of unconventional development, Wood Mackenzie says that suggestions from analogues from other plays would be break-even costs of about $US7 at the wellhead, which, when delivered to east coast market, you're talking $A12-13-plus."*[59]

Taking the lower range of the Wood Mackenzie analysis gas could be delivered to Gladstone for US$9/GJ before liquefaction and shipping. That compares with a current Japanese contract price of US$5/GJ. At current prices Northern Territory unconventional gas is entirely uneconomic.

Figure 6.1: Model of the Tariff Structure of the NEGI

NEGI Possible Tariff Structure					
NEGI Capacity (12 inch pipe)	90	TJ/day			
NEGI Capacity pa	32.85	PJ	32,850,000	GJ	
Incitec contract	10	PJ pa			
NEGI Capital Cost	650	($m)			
Return on Assets required	5.20	%			
Required EBITDA return	33.8	($m)			
Gross Profit margin required	52.6	%			
Revenue Required	64.3	($m)			
Petajoules transported pa	10	15	20	25	32
Tariff required $/GJ	6.43	4.28	3.21	2.57	2.01

When we model the possible tariff structures of the NEGI it is really just an academic exercise. This model assumes that the NEGI is constructed on an arms length economic

[58] Solving for "x" Page 15

[59] http://www.energynewspremium.net/storyview.asp?storyID=826958390&section=On+the+Record&sectionsource=s121&aspdsc=yes&utm_medium=email&utm_campaign=ENP+Standard2015-11-25&utm_content=ENP+Standard2015-11-25+CID_f8da02dc34d653bb8d37d5e2eaa297ef&utm_source=C

basis. In the case of the NEGI this is not true. The NEGI is being built to dispose of gas that was acquired by the Northern Territory government's Power and Water Commission under a take or pay arrangement. Essentially if the PWC can dispose of this gas for any return it is better off than just paying for the gas and not taking delivery.

It is also conjecture as to how extensive the extent of the fossil fuel subsidy involved should the NEGI receive funding from the Northern Development fund. In essence this is a transaction between the Government of Australia and the governments of Singapore and China. It is not a commercial transaction.

What the model does show is that this is going to be a high tariff pipeline in the Australian context. Even if it is virtually used at capacity the tariff required does not compare favourably to other gas pipelines in Australia in a $/km sense refer Figure 6.2.

Figure 6.2: Australian Pipelines, Capacities and Tariffs

Table 2: Pipelines and Pipeline Capacity

Gas Pipeline (t_j)	Pipeline name	Length (km)	From Node (η_i)	To Node (η_i)	Max Flow (TJ/d) (fc_i)	Tariff ($/GJ) (p_k)
CBR	Canberra to Dalton	58	Dalton	Canberra	77	$0.04
CGP	Carpentaria Gas Pipeline	840	Ballera	Mt Isa	119	$1.44
EGP	Eastern Gas Pipeline	797	Longford	Sydney	294	$0.96
LMP	Longford to Melbourne Pipeline	174	Longford	Melbourne	1030	$0.24
MAP	Moomba to Adelaide Pipeline	1185	Moomba	Adelaide	253	$0.50
MSP	Moomba to Sydney Pipeline	1300	Moomba	Sydney	439	$0.82
NVI	NSW - Victoria Interconnect	88	Culcairn	Young	71	$0.15
NVI_1	NSW - Victoria Interconnect	320	Melbourne	Culcairn	92	$0.32
QGP	Queensland Gas Pipeline	627	Wallumbilla	Gladstone	145	$0.96
RBP	Roma to Brisbane Pipeline	438	Wallumbilla	Brisbane	240	$0.51
SEAGas	South East Australia Gas Pipeline	680	Pt Campbell	Adelaide	314	$0.58
SWP	South West Pipeline	150	Pt Campbell	Melbourne	353	$0.27
QSN	QSN Link Pipeline	937	Ballera	Moomba	527	$0.40
SWQP	South West Queensland Pipeline		Wallumbilla	Ballera	404	$0.85
TGP_1	Tasmanian Gas Pipeline	734	Longford	Bell Bay	129	$2.00
TGP_2	Tasmanian Gas Pipeline		Bell Bay	Hobart	129	$2.00
APLNG	APLNG Pipeline	530	Surat	Gladstone	1560	$0.55
QCLNG	QCLNG Pipeline	540	Surat	Gladstone	1510	$0.55
GLNG	GLNG Pipeline	435	Surat	Gladstone	1429	$0.55

Sources: ACIL Allen, AEMO, AGL Energy Ltd, APA, Frontier Economics.

Source: Solving for "x" – the New South Wales Gas Supply Cliff, Paul Simshauser and Tim Nelson, March 2014

6.2 Northern Australia Infrastructure Facility

Jemena did explore the option of funding from the Northern Australia Infrastructure Fund.[60],[61]

That fund does not start until the third quarter of 2016 and that timing was considered too late back in November 2015, but with ongoing delays, Jemena is likely to reconsider this decision.

State subsidies are almost impossible to model as any project can become a reality with enough tax payer dollars. However even with a 100% subsidy it is unlikely that the NEGI would lead to the development of an unconventional onshore gas industry in the Northern Territory as the initial costs of production and the costs to transport the gas to Gladstone are simply too high.

It would need substantially higher gas prices to develop the Northern Territory unconventional gas industry and with the current massive oversupply and weak demand out to 2030 we consider this an unlikely event.

[60] http://www.industry.gov.au/industry/Northern-Australia-Infrastructure-Facility/Pages/default.aspx
[61] http://www.smh.com.au/business/energy/gas/jemena-forced-to-reduce-nt-gas-pipeline-size-amid-drilling-opposition-20160401-gnwgmc.html

Institute for Energy Economics and Financial Analysis

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About the Author

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Bruce has been an investment analyst, fund manager and professional investor for over 32 years. He has worked for major domestic and international institutions including Perpetual Trustees, UBS, Nippon Life Insurance and BT. Bruce is an active participant in the national debate on energy issues in Australia and has been invited to present to a number of government enquiries into the electricity and gas industries.

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Appendix A: Jemena Group Breakup

Electricity Distribution Business Basic Financials

In 2015 the Electricity Distribution business accounted for 26% of group revenue and 43% of group Earnings Before Interest and Tax (EBIT).

	2014	2015	% change
Revenue ($'000)	332,111	473,937	+43
Earnings before Interest and Tax (EBIT) ($'000)	188,302	323,364	+72
EBIT Margin (%)	56.7	46.6	

The Electricity Distribution Business

Electricity distribution
Jemena Electricity Network ("JEN") is a Victorian electricity distribution business supplying electricity to over 320,000 homes and businesses through approximately 6,000 kilometres of distribution network. The network services 950 square kilometres of northwest greater Melbourne.

The Company owns a 34% interest in United Energy Distribution Holdings Pty Ltd ("UEDH"), the holding company of United Energy Distribution Pty Ltd ("UED"). UED distributes electricity throughout southeast Melbourne and the Mornington Peninsula in Victoria. The network covers approximately 1,472 square kilometres and services over 660,000 end users.

The Group holds a 50% interest in the ActewAGL Distribution Partnership ("ActewAGL"). ActewAGL owns, plans, develops, constructs, operates and maintains the electricity network in the Australian Capital Territory ("ACT") and the gas networks in the ACT, Queanbeyan and Nowra. The remaining 50% of the partnership is owned by Icon Distribution Investments Limited, a subsidiary of Icon Water Limited. Icon Water Limited (formerly ACTEW Corporation Limited) is an ACT government owned company with assets and investments in water, wastewater, electricity and gas.

Source: *Jemena 2015 Annual Report*

Gas Distribution Business Basic Financials

In2015 the Gas Distribution business accounted for 35% of group revenue and 44% of group EBIT.

	2014	2015	% change
Revenue ($'000)	527,033	619,610	+18
Earnings before Interest and Tax (EBIT) ($'000)	335,669	364,339	+9
EBIT Margin (%)	63.7	70.1	

The Gas Distribution Business

Gas distribution
Jemena Gas Network ("JGN") is a New South Wales ("NSW") gas distribution business established in 1837 and owns approximately 25,000 kilometres of natural gas distribution system, delivering approximately 90-100 petajoules per annum ("PJ p.a") of natural gas to more than 1.2 million homes and businesses across NSW.

Source: *Jemena 2015 Annual Report*

Gas Transmission and Water Distribution Business Basic Financials

In 2015 the Gas Transmission and Water Distribution business accounted for 12% of group revenue and 17% of group EBIT.

	2014	2015	% change
Revenue ($'000)	160,749	212,826	+32
Earnings before Interest and Tax (EBIT) ($'000)	96,453	130,527	+35
EBIT Margin (%)	60.0	61.3	

The Gas Transmission and Water Distribution Business

Gas transmission and water distribution

The Eastern Gas Pipeline ("EGP") transports gas 797 kilometres from the Gippsland Basin in Victoria to Sydney and regional NSW, and has a current capacity of approximately 129 PJ p.a.

The Queensland Gas Pipeline ("QGP") transports gas 627 kilometres from the Surat Basin, Denison Trough and Bowen Basin to Gladstone and Rockhampton, and has a current capacity of approximately 56 PJ p.a.

VicHub is a pipeline interconnect facility situated at Longford, Victoria. The facility enables gas to flow between the Eastern Gas Pipeline and the Victorian gas transmission system. The facility has a nominal daily capacity of 150 terajoules per day.

The Colongra Gas Pipeline ("Colongra") is a 9 kilometre, high pressure gas transmission and storage pipeline delivering gas to the Colongra peaking power station at Munmorah, NSW.

AquaNet Sydney is responsible for the Rosehill Recycled Water Scheme, delivering high quality recycled water for industry and irrigation through a 20 kilometre network.

Source: *Jemena 2015 Annual Report*

Services Business Basic Financials

In 2015 the Services business accounted for 32% of group revenue. It made a small loss for the year.

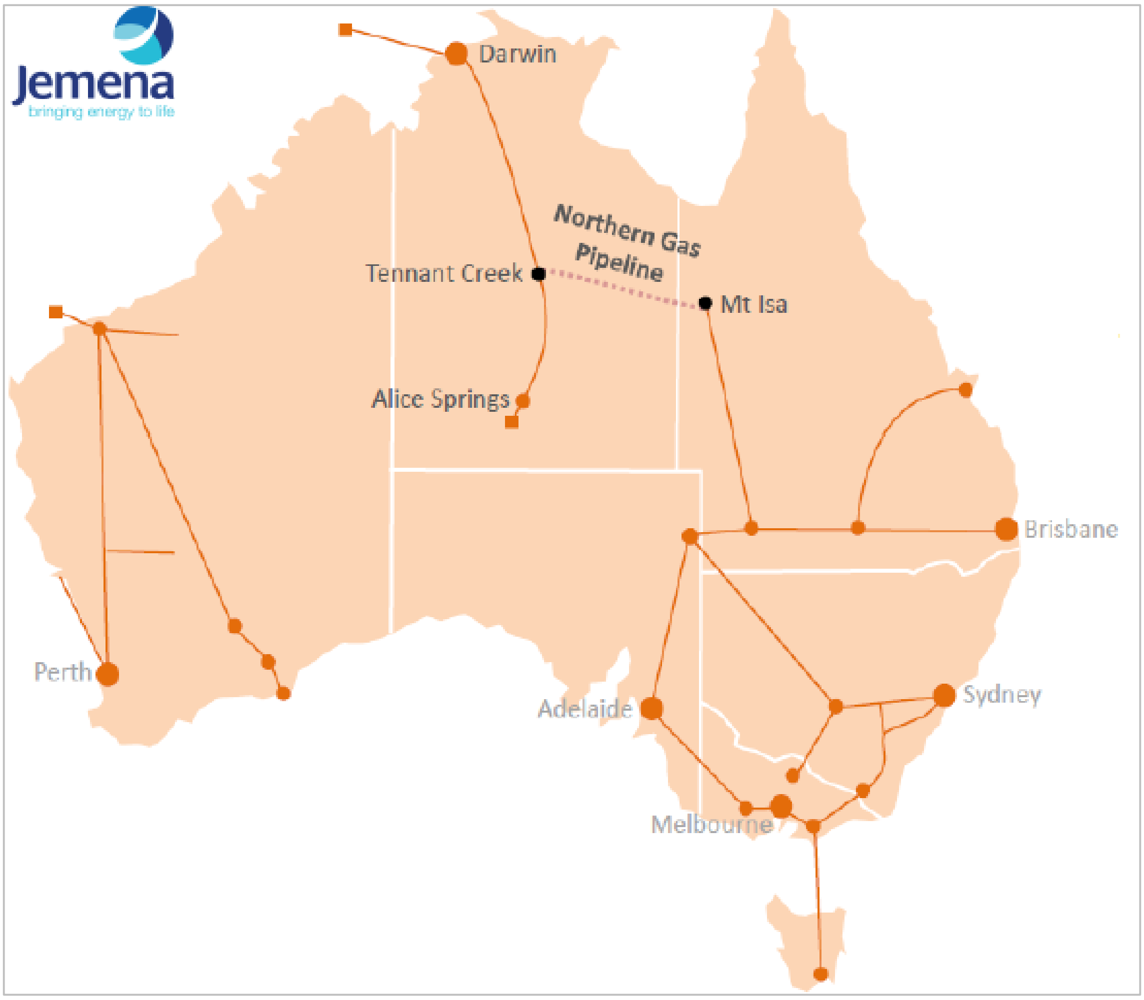
	2014	2015	% change
Revenue ($'000)	446,950	570,359	+28
Earnings before Interest and Tax (EBIT) ($'000)	3,040	(4,394)	-
EBIT Margin (%)	0.7	-	

Services business

Zinfra Group provides engineering and design, project management, construction, civil, maintenance and asset operations services to the Australian utility infrastructure sectors and adjacent markets.

Source: *Jemena Annual Report*

Appendix B: Australia's Gas Pipeline Network



Source: Jemena Business Briefing Mt Isa, Presentation, March 2016