Australia's Export LNG Plants at Gladstone: The Risks Mount

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Executive Summary

The Australian Coal Seam Gas (CSG)-to-Liquid-Natural-Gas (LNG) industry began auspiciously, with its champions promising export revenue, royalties and jobs.

The three plants at Gladstone were built during one of the great resource booms of the past 100 years. Demand out of Asia for LNG appeared almost limitless at the beginning of this decade.

However, demand by the world's largest LNG importer, Japan, has been shrinking, and growth in China and other emerging markets has failed to keep up with the boom in supply. Nominal global liquefaction capacity closed 2016 significantly oversupplied—29% above demand, and the gap between supply and demand widened over the year despite very low prices.

Even with growth in some emerging markets, and growth in some developed markets like South Korean and Taiwan, the global LNG market remains significantly over supplied.

This glut in global supply will very likely deepen, until 2020 at least, by which time supply will have increased by 34% to 456 MTPA. Global demand will simply not take up the slack.

IEEFA expects that the expanding glut will put relentless downward pressure on prices and lead to many contract defaults and renegotiations.

It is a truism in the LNG supply industry that the product is expensive to store, so the glut we describe in this paper can only be resolved by LNG processing capacity being curtailed.

In all resource markets, highest-cost producers have to curtail production first.

The three Gladstone plants sit at the very apex of the global cost curve, so these plants that will feel the pressure to shut in capacity most acutely. IEEFA expects some liquefaction trains at Gladstone to cease production altogether over the next two years.

The LNG industry in Eastern Australia is fundamentally weak because its elements were developed in the wrong order.

Export contracts were secured, plants were approved with no consideration of the domestic market, plants were built and finally gas fields were developed. Along the way, the gas industry failed to contain the cost of building three plants concurrently, a misstep that led to globally uncompetitive capital costs. The industry found that when it went to drill for gas—after having secured gas contracts and built the plants—that the CSG fields that were expected to supply the plaints failed to produce the gas expected.

Capital costs of the plants at Gladstone, and operating costs of the gas fields that supply Gladstone, are globally uncompetitive.

What is particularly worrying for the industry in this case is that the very best CSG fields have been drilled, and costs will rise further from here.

IEEFA estimates that if Santos were to write down the value of its Gladstone investment, GLNG, to global comparatives it would amount to a write off up to $3.3 billion. Origin Energy would face write downs of a similar magnitude on its investment in APLNG.

As a direct result of a massive overbuild of LNG capacity, Australian East Coast domestic gas markets are undersupplied, leading to globally uncompetitive, record high gas prices. We are seeing prices in Australia for both contract and spot gas well in excess of what customers pay in North Asia.

After five decades of least-cost domestic gas supply, industry is showing an inability to now supply gas at even export price parity, putting the government under ever-increasing pressure to intervene and secure remotely affordable energy supplies for both residential and industrial consumers.

The various solutions proposed by the industry—producing more gas at Narrabri, fracking in the Northern Territory, opening an LNG import facility in NSW or even supplying the East Coast with a prohibitively long and expensive pipeline from Western Australia—are all uneconomic. The gas supplied under such proposals would be at a price above the world's most expensive market, Japan. Producing expensive wellhead gas and then adding expensive pipeline charges is no way to bring down the domestic price of gas.

Accounts of the market published by the oil and gas industry in Australia lack integrity. Oil price forecasts, currency and discount rate assumptions all vary significantly, leading to asset values that are inconsistent. IEEFA estimates that if official forecasts for oil prices from the Office of the Chief Economist were used, the value of GLNG, according to Santos's latest accounts, could be overstated by in excess of US$1billion.

IEEFA recommends that Australia adopt U.S. standards that require that reserves be calculated using the same oil price. We also recommend adoption of U.S. disclosure rules that mandate reporting by field, of average sales prices for oil and gas produced, and average production costs.

Such consistent and comprehensive disclosure would support the formulation of sensible government policy on energy.

The companies involved in LNG production on the East Coast of Australia will continue to produce at a net loss for as long as their shareholders will allow them—in the hope that some geopolitical event will send LNG prices up. To date, despite massive drops share price and large and continuing write-offs, investors appear to be willing to commit more equity capital.

However, as the glut deepens and balance sheets continue to deteriorate, investor patience will be severely tested.

Australian governments would do well now to make a clear and unequivocal choice. Either they continue to back the gas industry (the architects of this problem) at the expense of all Australians, or they can choose—as every other sovereign nation on earth does—to ensure that Australia's natural resources are used at the very least to provide domestic energy at a reasonable cost.

This report examines where the three East Coast CSG-to-LNG export plants at Gladstone fit into the global landscape for natural gas.

Introduction

In 2016, IEEFA released a global study of LNG supply and demand that questioned the proposed construction of the North East Gas Interconnector (NEGI) "Pipe Dream, A Financial Analysis of the Northern Gas Pipeline.[1]

The study showed how the global gas market was both already oversupplied and that oversupply would get worse due to the large amount of new supply capacity that was additionally under construction.

That study showed also how demand growth in the world's largest importing nations was weak.

The combination of committed supply expansions and weak demand led IEEFA to conclude that the LNG market would remain oversupplied out to 2030.

Global Supply Demand Balance

Large increases in supply have again been confirmed by both the GIIGNL and the International Gas Union,[2] which stated that global nominal liquefaction capacity as at January 2017 was 340 MTPA, a rise of 12% over 2016.

Global liquefaction capacity is expected to grow by an additional 34% between 2017 and 2020, with 116 MTPA currently under construction.

While supply grew by 12% over 2016, demand, after being relatively flat between 2011 and 2015, grew at 7.5%. Imports totalled 263.6 MT in 2016. The global gas glut grew over 2016 as supply growth outstripped demand growth.

Nominal global liquefaction capacity closed the 2016 year 29% above demand.

The market is significantly over supplied, and this glut will very likely deepen significantly out to 2020 with a further increase in supply of 34% to 456 MTPA.

[1] http://ieefa.org/wp-content/uploads/2016/05/Pipe-Dream-A-Financial-Analysis-of-the-NEGI-MAY-2016.pdf
[2] GIIGNL Annual Report 2017
2017 World LNG Report – International Gas Union

Table 1 – Liquefaction Plants Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*
Australia	Australia Pacific LNG T2	2017	4.5	ConocoPhillips, Origin Energy, Sinopec
Malaysia	PFLNG Satu	2017	1.2	PETRONAS
Indonesia	Senkang LNG T1	2017	0.5	EWC
United States	Sabine Pass LNG T3-4	2017	9	Cheniere Energy, Blackstone
Australia	Ichthys LNG T1	2017	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Cameroon	Cameroon FLNG	2017	2.4	Golar, Keppel
Australia	Gorgon LNG T3	2017	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA
Australia	Wheatstone LNG T1	2017	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA
Russia	Yamal LNG T1	2017	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Cove Point LNG	2017	5.25	Dominion
Australia	Ichthys LNG T2	2018	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Australia	Wheatstone LNG T2	2018	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA
United States	Elba Island LNG T1-6	2018	1.5	Kinder Morgan
Australia	Prelude FLNG	2018	3.6	Shell, INPEX, KOGAS, CPC
United States	Cameron LNG T1	2018	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
Russia	Yamal LNG T2	2018	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Cameron LNG T2	2018	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Freeport LNG T1	2018	5.1	Freeport LNG, JERA, Osaka Gas
United States	Corpus Christi LNG T1	2019	4.5	Cheniere Energy
United States	Elba Island LNG T7-10	2019	1	Kinder Morgan
United States	Freeport LNG T2	2019	5.1	Freeport LNG, IFM Investors
United States	Corpus Christi LNG T2	2019	4.5	Cheniere Energy
United States	Cameron LNG T3	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Sabine Pass LNG T5	2019	4.5	Cheniere Energy, Blackstone
Russia	Yamal LNG T3	2019	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Freeport LNG T3	2019	5.1	Freeport LNG
Indonesia	Tangguh LNG T3	2020	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui
Malaysia	PFLNG 2	2020	1.5	PETRONAS
Malaysia	PFLNG 2	2020	1.5	PETRONAS

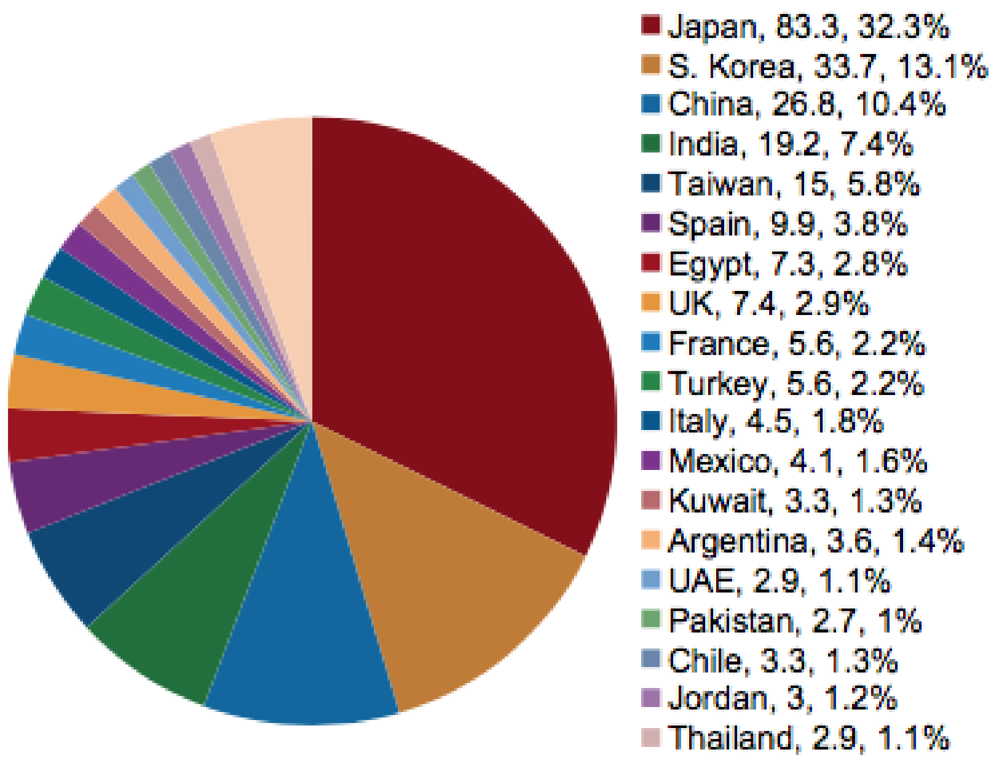
Sources: IHS, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake.*

Source: 2017 World LNG Report, International Gas Union Page 68

Global LNG Trade

As the chart below illustrates, Asia dominates the global LNG trade, taking 54% of global supply. Japan alone accounts for 32% of the global trade in LNG.

Figure 1 - LNG Imports and Market Share by Country (MTPA)



Note: Number legend represents total imports in MT, followed by market share %. "Other" includes countries with imports less than 2.5 MT (by order of size): Singapore, US, Portugal, Puerto Rico Belgium, Malaysia, Brazil, Lithuania, Poland, Dominican Republic, Greece, Netherlands, Israel, Canada, Jamaica, and Colombia. Sources: IHS Markit, IGU

Source: 2017 World LNG Report – International Gas Union Page 11

Demand in Japan

After falling for two years, Japanese imports dropped again in 2016 by an addition further 2% to 83MT. Since, 2014 Japanese LNG demand has fallen by 7%.

According to Platts, the well-respected industry forecaster:

"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 as much as 10.5% from 2014 levels."[3]

Decline in LNG demand forecast in Japan is now materialising.

Demand in China

Chinese natural gas imports were up by 35% in 2016 to 26.8 MTPA.

While Japan is the world's largest current LNG importer, the gas industry is pinning its hopes of expansion on China. While we do see growth in gas demand in China, we see it as a fundamental mistake to conflate a rise in gas consumption with a rise in demand for LNG.

According to the International Gas Union, natural gas accounts for roughly a quarter of all global energy demand, of which only 9.8% is supplied as LNG.[4] Piped gas dominates the supply chain in gas globally.

We see five principal dynamics crimping demand for LNG in China:

1. The rise of renewable energy and energy efficiency.

   As Tim Buckley, IEEFA director of energy finance studies, Australasia has noted:

   "China plans to invest US$360bn in new renewable energy capacity by 2020, driving new employment and technology development. A world record 33.2 gigawatts (GW) of solar was installed in 2016, double China's then record 15GW installed in 2015, which itself was double the highest ever German record annual installs of 7.6GW achieved back in 2012. On-grid utility solar grew 34% yoy to 39TWh in 2016. In terms of wind, China installed 'just' 17.3GW in 2016, down from the record annual install of 29GW in 2015, again set by China. Wind generation grew 19% to 211TWh."[5]

2. The growth of a domestic gas industry. China is rapidly expanding its shale gas fracking industry. The U.S. Energy Information Administration estimates that China contains the largest technically recoverable shale gas reserves in the world, 1,115 tcf as of September 2015. Although 2015 results from the industry were below expectations, 2016 production was stronger.[6] It is still early days for the Chinese shale

[3] https://www.platts.com/latest-news/natural-gas/tokyo/japan-lng-demand-expected-to-fall-by-2020-on-27051779
[4] 2016 World LNG report – International Gas Union page 5
[5] http://reneweconomy.com.au/coal-hit-as-chinas-energy-transition-gathers-pace-18419/
[6] http://www.ogj.com/articles/2016/11/china-s-shale-gas-production-outperforms-expectations.html

gas fracking industry but reserves in China are massive and the government is focused on national energy security.

3. The increasing impact of global geopolitics as energy security issues become more important. Example: China, given its ambitions in the South China Sea, is likely to want to diversify away from energy sourced from countries allied to the U.S.

4. Increased Russian supply. On 21 May 2014, Gazprom and CNPC (China National Petroleum Corporation) signed a US$400bn contract to supply gas from Russia via the eastern route, the Power of Siberian pipeline. Terms of the 30-year contract equate to 28Mtpa of LNG.[7] A second large pipeline deal was signed on 8 May 2015, for a western route (Power of Siberia-2 pipeline[8]) that equates Initially to 22Mtpa of LNG. These two large deals will transform the Chinese energy landscape.

5. Fugitive emissions. The fugitive emissions of the CSG-to-LNG industry are not well known. A recent study by the Melbourne Energy Institute[9] highlights the knowledge gaps in current reporting methods. It is possible that emissions are far higher than acknowledged, which would make imported LNG from Gladstone less attractive to the Chinese.

Demand in South Korea & Taiwan

May 2017 saw the newly elected South Korean President Moon Jai-in commit to an energy policy that will reduce South Korea's reliance on imported coal and nuclear power. The president's policy is rooted in mounting air pollution pressures and civil resistance to more nuclear power facilities. While energy efficiency and renewable energy will see significantly more focus, the new policies will likely also boost LNG demand.

As it is very early days in this presidency, it is hard to quantify the boost to South Korean LNG imports that may occur. If we assume that South Korea increases its imports of LNG by 50% by 2025 it would mean importing an additional16.5 MTPA of LNG.

Taiwan President Tsai Ing-wen is likewise pursing an aggressive electricity market transformation program. May 2017 saw the unveiling of the nation's eight-year green energy development plan to 2025. The key forecasts are for coal's market share to decline from 45% in 2016 to a target of just 30%, a total nuclear phase-out by 2025, and growth in renewables from 5% of market share in 2016 to 20% by 2025 (with wind farm investments of 4.2GW forecast). LNG is forecast to see a major revitalization in Taiwan, with its market share forecast to increase from 32% in 2016 to 50% by 2025.[10] This could result in an additional 8MT of demand by 2025.

If Korea and Taiwan were to increase LNG imports aggressively out to 2025, as outlined above, it would not materially impact the LNG glut. The 2016 year closed with nameplate capacity exceeding demand by 76MT with a further 116MT of capacity currently under

[7] https://www.theguardian.com/world/2014/may/21/russia-30-year-400bn-gas-deal-china
[8] http://www.gazprom.com/press/news/2015/december/article256006/
[9] http://energy.unimelb.edu.au/__data/assets/pdf_file/0019/2136223/MEI-Review-of-Methane-Emissions-26-October-2016.pdf
[10] http://www.taiwannews.com.tw/en/news/3162578

construction out to 2020. Taiwan and Korea's expansion plans combined—best case—would soak up only 25 MTPA of capacity by 2025.

Indeed, the aggressive expansion of Taiwan and Korea on LNG imports highlights the size of the global LNG glut. Even with large demand in large LNG markets—the combined effect of Taiwan and Korea in this case—would absorb just 6% of the current level of oversupply[11] by 2020.

Newly-Emerging Markets

We have seen that demand for LNG in price-sensitive emerging markets has grown strongly with low spot prices and plentiful supply.

Indian demand grew by 30%, reaching 19MT in 2016, reflecting both its declining domestic gas production and the introduction of short-term subsidies for LNG importation for use in peaking gas-fired power plants. Likewise, Bangladesh has been in a growing gas crisis given its declining domestic gas production and strong electricity demand growth; Bangladesh has intentions for a significant lift in LNG import capacity – albeit no plan on how its heavily subsidised and loss-making Power Development Board will cover the significant gap to import price parity on LNG.

Likewise, the emerging markets of Egypt, Pakistan and Jordan imported a combined 13.5 MT in 2016 versus 5.5MT in 2015.[12] This growth was driven mostly by Egypt, where imports almost tripled from 2.6 MT in 2015 to 7.5MT in 2016.[13]

Egypt's rapid growth in LNG imports in 2016 will reverse in coming years, however, as new oilfields are brought on-line. New fields have been opened up already by BP (West Nile delta and Atoll fields) and by ENI's (Zohr field). The Egyptian Natural Gas Holding Company is looking to defer a number of LNG import cargoes scheduled for 2017. In addition, it is looking to cancel up to 40 LNG cargoes for delivery in 2018.[14]

These emerging markets are very price sensitive and may curtail imports in the event of rising LNG prices. The coming turnaround of Egypt from importer to net exporter of LNG will put pressure on global prices.

New Supply in the Early 2020's

The collapse in global LNG prices is not proving to be a major disincentive to globally low-cost gas producers such as the U.S. and Qatar, which are developing new export projects.

The U.S., under its new administration, is looking to ramp up LNG exports:

"We could be and should be the largest exporter of LNG in the world," Gary Cohn, direct of the White House National Economic Council said in April 2017 at the Institute of International

[11] Assumes that half the expansion of Taiwan's and Korea's LNG demand out to 2025 would occur by 2020.
[12] GIIGNL 2017 Annual Report Page 5
[13] GIIGNL 2017 and 2016 Annual Reports page 15
[14] http://www.lngworldnews.com/report-egypt-to-cut-down-on-lng-imports/

Finance forum in Washington. "We're going to permit more and more of these LNG plants."[15]

Qatar has just lifted a 12-year ban on developing its North Field.[16]

Despite the international LNG market being oversupplied already new capacity may emerge after 2020 from these two low-cost producers. Indeed U.S. and Qatar producer costs are so low that they can make a return at prices that would put high-cost producers such as those at Gladstone out of business. Additionally, Japan has been providing financial support for new LNG export capacity in the U.S. as a way of cementing the breakdown of the oil-inked LNG pricing regime that has been staunchly in place over the past few decades, facilitating a move toward a Henry Hub pricing basis. This would boost Japan's geographic diversity of supply as an attempt to build energy security of import supply.

Global Demand/Supply Balance

The market is significantly over supplied. Nominal global liquefaction capacity closed the 2016 year 29% above demand. This glut will deepen significantly out to 2020 with a further increase in supply of 34%, to 456 MTPA.

A defining feature of the gas market is the expense of storing gas. Long-term storage is problematic for importing countries.

Like any market, the LNG gas market will rebalance, and the way in which this will occur has been succinctly outlined by the President of the GIIGNL (International Group of Liquefied Natural Gas Importers), Jean-Marie Dauger:

> "Looking at future years, with Australian projects ramping-up and new trains from the United States progressively coming online, the global LNG market could become oversupplied until the mid 2020s."
>
> "Surplus capacity could be progressively absorbed by additional imports and/or by shut-ins, both as a consequence of low price levels, resulting in a market rebalancing in the last part of the decade."[17]

While new imports markets for the currently cheap LNG are being found, and traditional LNG importers China, Taiwan and Korea are increasing demand, demand growth is simply not matching supply growth.

This leaves a situation by which the industry will face shut-ins, or caps on, production capacity. The highest-cost producers are vulnerable to market rebalancing, the three plants at Gladstone especially so.

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[15] https://www.bloomberg.com/news/articles/2017-04-20/white-house-s-cohn-wants-to-see-more-and-more-lng-terminals

[16] http://www.cnbc.com/2017/04/03/reuters-america-update-4-qatar-restarts-development-of-worlds-biggest-gas-field-after-12-year-freeze.html

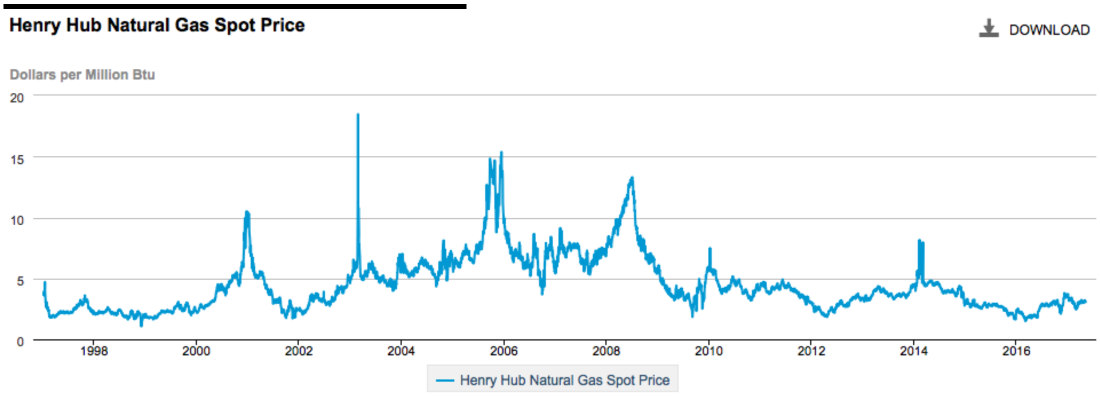
[17] Quote from the Jean-Marie Dauger – President GIIGNL page 2 GIIGNL Annual Report 2017

Collapse in Gas Prices

Globally, gas prices collapsed from 2014 to 2016, as can be seen in the industry-sponsored International Gas Union. Average Japanese import prices fell from US$14.79/GJ($A16.38) in 2014 to US$ 5.23/GJ (A$7.03/GJ) in 2016.[18]

In the U.S., spot gas prices have halved, falling from a high of US$4-6.00/GJ in the first quarter of 2014 to a recent price averaging US$ 3.10/GJ in April 2017.

Figure 2 – US Spot Gas Prices at the Henry Hub

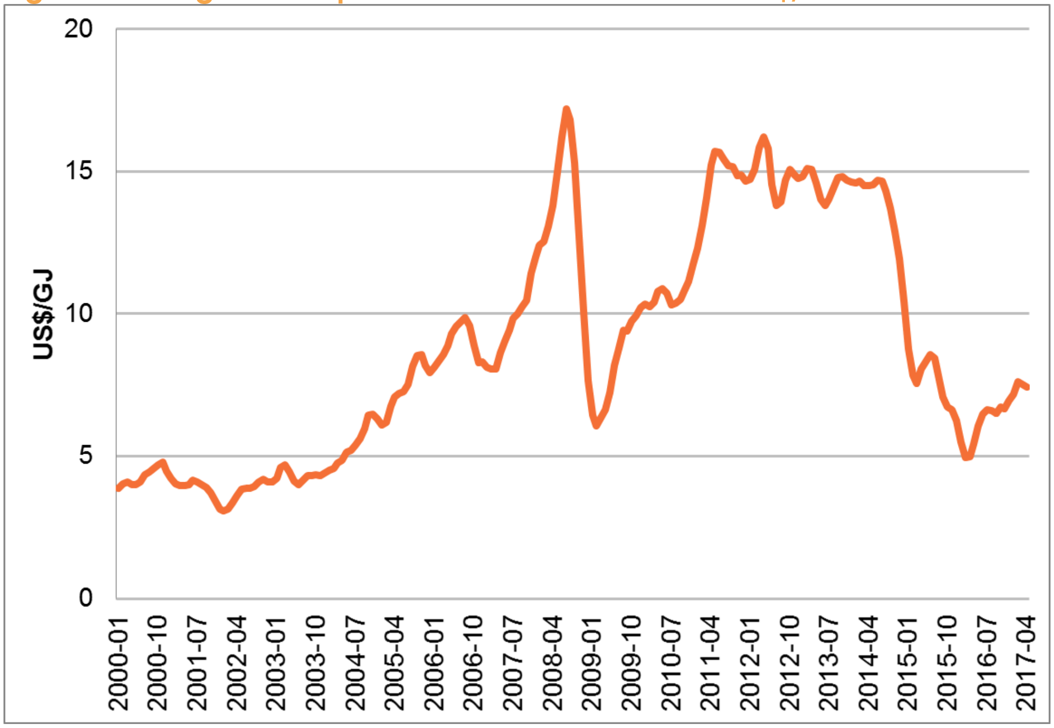


Source: https://www.eia.gov/dnav/ng/hist/rngwhhdW.htm

In Japan, the collapse in oil-linked contract prices are similar to those in the U.S. Implied contract prices hit a high of US$14.75/GJ in June of 2014 and now stand at about half that level, at US$7.44/GJ.

[18] IGU World LNG Report – 2017 page 4

Figure 3 – Long-Term Japanese Gas Contract Prices US$/GJ



Source: ACCC, RBA, EIA and IEEFA calculations

Gas Contracts

Customers Becoming Competitors

Japan and South Korea, Australia's major customers for LNG, have overestimated demand for LNG and have consequently had to start re-exporting contracted volumes[19]. This creates special problems, as there are destination clauses in some of the contracts that make it compulsory for the gas to be offloaded at a specific port. These destination clauses are a key plank in the contract system along with the oil-linked pricing mechanism in the contract and the long-term nature of the contracts.

However, the problem major gas consumers face is weak demand for LNG. The nuclear industry is gradually restarting in Japan, and in both South Korea and Japan, renewables are growing while coal has got cheaper. In addition, energy efficiency and new energy saving appliances are putting sustained pressure on demand.

After the Fukushima nuclear disaster and in the face of significant electricity price rises, Japanese consumers have embraced energy efficiency. Once consumer power-consumption habits change, consumers seldom revert back to their old consumption

[19] boereport.com – "World's Biggest LNG Buyer Becomes Seller as Gas Glut Builds" Bloomberg 26 May 2016.

patterns—even after a crisis has ended. Total Japanese electricity demand in 2016/17 is down 12% from the peak in the 2010/11, the year prior to Fukushima. Additionally, in March 2017, Japan passed the 100GW threshold in terms of cumulative installs of renewable energy, a near doubling of capacity in five years.

Japan also faces declining population as its population ages. Resistance to immigration is fierce.

A fundamental aspect of the LNG industry—of any industry—is there must be someone, somewhere to use the product. LNG is expensive to store. Japan and South Korea have over-contracted LNG supplies. This glut in supply has led to Japan starting to re-export gas, which means effectively that major customers are now competitors in the global market for gas. This phenomenon places further pressure on an already over-supplied market.

Japan's Fair Trade Commission is currently investigating whether the destination clauses in the contracts are anti-competitive[20]—which is to say whether they can be nullified. It is a possibility that many long-term contracts with Japan may have to be renegotiated.

Japan is Oversupplying its Domestic Market

The Japanese market is oversupplied as domestic demand falls and as contracts to supply ramp up Japan continues nonetheless to increase and diversify its sources of supply.

In December 2016, Russia's Yamal LNG project, whose largest shareholder is Novatek, signed a US$209m credit line facility with the Japan Bank for International Cooperation (JBIC).[21]

Yamal is a large new LNG project in the arctic circle with an annual capacity of 16.5 MTPA. It is nearly complete and expects to ship its first cargoes in October of 2017.

Novatek has signed a memorandum of understanding with Mitsui, Mitsubishi and Marubeni regarding the supply of LNG. By increasing and diversifying supply into an already over supplied market, Japan is ensuring low gas prices into the future for the world's biggest LNG market.

Spot Prices Diverging from Contract Prices

Contract gas prices to Asia are oil-linked. If the price of oil rises, this linkage could lead to contract prices rising in a market that is over-supplied. The over-supply situation will result in spot prices remaining low.

The situation is unsustainable, and eventually the contract system will break down, a breakdown driven by the expansion of Henry Hub-linked LNG supply from the U.S.

[20] http://www.bloomberg.com/news/articles/2016-07-14/japan-said-to-review-if-lng-contracts-barring-resale-violate-law-iqlr1xu7
[21] http://www.green4sea.com/novatek-signs-mou-japanese-firms-lng-projects/

Contracts Are 'Flexible'

Analysts at the Reserve Bank of Australia (RBA) say contracts have become more flexible since the 1990s and "incorporate additional features to address pricing risk."

"Some newer contracts have flexibility on fixed destination clauses and take-or-pay commitments, and a greater share of sales contracts are under more-flexible free-on-board (FOB) agreements. 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."[22]

This new flexibility in contract requirements further undermines LNG markets.

Contracts Are Breaking Down

Long-term LNG contracts are already breaking down in the face of the global oversupply of gas. In late December 2015, after much negotiation, Qatar's Rasgas and India's Petronet LNG Ltd agreed to a renegotiated deal.

The deal had two parts. First, Rasgas agreed to waive $1.8 billion in contract penalties that were due as Petronet did not take contracted LNG volumes in 2015. Second, the price agreed to was half the previous price.[23]

This deal suggests a taste of what is to come in 2017.

To date, none of the major contracts between Japanese customers and Australian producers have publicly failed. However, with the added pressures of declining electricity demand and financial distress for much of the Japanese power sector, Japanese utilities are looking to lower LNG purchase prices, change pricing mechanisms and rely more on the spot market for gas.

As Reuters describes the situation:

"The utilities want to rid themselves of fixed-volume LNG supply contracts with time frames that can last a generation, and are set to push hard during pre-set negotiating periods in long-term contracts."

Jera Co. Inc., which operates as a joint venture of Tokyo Electric Power Company and Chubu Electric Power Company, plans to cut the amount of LNG it gets from long-term contracts by 42 percent by 2030. And Japan's second-biggest city-gas supplier, Osaka Gas, has said it may not sign new long-term LNG contracts for the next several years."[24]

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[22] Page 37 https://www.rba.gov.au/publications/bulletin/2015/mar/pdf/bu-0315-4.pdf
http://www.smh.com.au/business/energy/oils-aint-oils-gas-contracts-aint-gas-contracts-20151016-gkazm5.html October 2015

[23] www.bloomberg.com "RasGas, Petronet Revise LNG Contract to Lower Indian Prices" December 31, 2015

[24] http://af.reuters.com/article/energyOilNews/idAFL3N1C33RZ

Summary and Conclusion

The global gas market is oversupplied, demand growth is weak and more supply is coming on stream between now and 2020.

LNG producers face low prices for contract-supplied gas. If the oil-linked contracts recover in price, it is likely that a cascade of contract renegotiations will follow.

Either way, because of the excess of LNG available globally, it is likely that prices will remain low for the foreseeable future, putting high-cost producers at extreme risk.

An Economic History of the Three CSG-to-LNG Plants at Gladstone

Introduction

The boom in LNG export plants that includes those at Gladstone began with the earthquake and tsunami that caused the nuclear reactor at Fukushima to melt down. The entire Japanese nuclear industry was shut virtually overnight as a result, withdrawing 30% of all Japanese generating capacity from service.

Japan turned to imported thermal fuel, including LNG, to fill the gap, and prices in the tightly traded market spiked to around $20/GJ. This price signal caused a rash of new investment proposals concentrated in the U.S. and Australia.

Engineering, planning and construction (EPC) capacity was stretched to the breaking point, and cost overruns of 20-30% were commonplace. Several high-cost gas projects—like those at Gladstone—were developed to supply what seemed like an insatiable Asian demand for gas.

Criticism of the rush to build and supply was eloquently stated by Woodside CEO Peter Coleman in 2016 at the Australian Petroleum Production and Exploration Association (APPEA) conference in June 2016:

> *"Mr. Coleman pointed to the $200 billion figure that is cited for investment in liquefied natural gas over the past 10 years in Australia and said it was nothing to be proud of, given that the original budgeted figure was so much lower."*
>
> *"'Whilst we may wax lyrical about the $200 billion, it actually started as $100 billion,' he told the APPEA oil and gas industry conference in Brisbane on Tuesday."*
>
> *"'We didn't deliver on our promise. We delivered a very expensive energy source,'" he said, taking the industry to task for losing investment discipline, making projects too*

complex, and losing touch with gas markets."[25]

The Three Gladstone LNG Facilities

The three Gladstone LNG facilities are all two-train facilities with similar annual capacities of 7.8 to 9 MTPA. Each is a project of customer and investor consortiums of three to four shareholders. The operators are Shell, Santos and Origin Energy/Conoco Philips.

QCLNG was the first of the three plants to produce LNG, in December of 2014, and APLNG was the last to come on line, in October 2016.

Table 2 - Commencement Dates of Terminals at Gladstone

Consortium	Terminal	Capacity	Start Date
APLNG	T1	4.5	December 2015
	T2	4.5	October 2016
GLNG	T1	3.9	October 2015
	T2	3.9	May 2016
QCLNG	T1	4.3	December 2014
	T2	4.3	July 2015

Sources: APLNG, Santos GLNG, Gladstone Observer, GIIGNL 2017 Annual Report

[25] http://www.smh.com.au/business/energy/woodside-petroleum-ceo-peter-coleman-says-gas-industry-out-to-lunch-20160607-gpd5rx.html

Table 3 – Background on Gladstone Plants

Project	Annual Capacity (MT)	Consortium Lead	Shareholders	Shareholder Percentage	Comment
Australia Pacific LNG (APLNG)	9	Origin Energy	Origin Energy	37.5	Origin Energy is an Australian Stock Exchange listed public company. Origin is responsible for the operation of the APLNG gas fields and the main gas transmission pipeline.
		Conoco Philips	ConocoPhillips	37.5	ConocoPhillips is a US based oil and gas multinational. It is responsible for the construction and operation of the two train APLNG facility on Curtis Island.
			Sinopec	25	Sinopec Group is China's second largest crude oil and natural gas producer. It is China's largest petroleum products and chemicals producer and supplier.
Santos Gladstone LNG (GLNG)	7.8	Santos	Santos	30	Santos is an Australian Stock Exchange listed public company
			Petronas	27.5	Petronas is Malaysia's national oil and gas company and the worlds second largest exporter of LNG.
			Total	27.5	Total is a large french integrated oil and gas major
			Kogas	15	Kogas is short for Korean Gas Corporation- the worlds largest LNG importer
QCLNG	8.5	Shell	Shell	73.75	Shell took over British Gas (BG Group) in February 2016. BG had in turn taken over Queensland Gas Company in November 2008. Shell also owns Arrow Energy.
			CNOOC	25	China National Offshore Oil Corporation ("CNOOC"), the largest offshore oil & gas producer in China, is a state-owned company operating directly under the State-owned Assets Supervision and Administration Commission of the State Council of the People's Republic of China. Founded in 1982 and headquartered in Beijing.
			Tokyo Gas	1.25	Tokyo Gas is a supplier and distributor of gas and electricity into Japan.

Sources
http://www.santosglng.com/faqs.aspx
https://www.aplng.com.au
http://www.bg-group.com/files/pdf/qgc/2481_qgc-bg_ausprofile.webfinal.pdf

Contracts at Gladstone

All three projects have large, typically 20-year contracts with their customers. All contracts are linked to the price of oil and were struck when oil prices were over USD 100/ barrel (prices are now in the USD 50/barrel range). These plants required long-term contracts to attract the billions of dollars that went into building the facilities; typically, companies look to lock in 85% of output prior to commencement.

One of the defining features of the LNG industry in Australia is its lack of transparency, a characteristic that leaves the government essentially in an information void on energy policy. Reliable data on export prices attained at Gladstone is simply not available.

Table 4 – Export Contracts from Gladstone's LNG Plants

Seller	Buyer	MTPA	Duration	Type of Contract
QCLNG	CNNOC	3.6	2014/2034	DES
	Shell	up to 8.5	2014/2034	FOB
	Tokyo Gas	1.2	2015/2035	DES
GLNG	Kogas	3.5	2015/2030	FOB
	Petronas	3.5	2015/2035	DES
APLNG	Kansai Electric	1	2016/2036	FOB
	Sinopec	4.3	2016/2036	FOB
Source:	Page 10 GIIGNL annual report 2017			

Definitions

FOB	Term of sale under which the price invoiced or quoted by a seller includes all charges up to placing the goods on board a ship at the port of departure specified by the buyer.
DES	Transaction in which the seller fulfils its obligations by delivering the goods aboard a ship at a specified port in the importing country.[26]

Four of the seven contracts at Gladstone are under the more flexible FOB arrangements.

One of the major contracts for the QCLNG plant, the Shell contract, even states that the volumes are "up to" 8.5 MTPA.

This would appear to give Shell the flexibility to accept lower volumes.

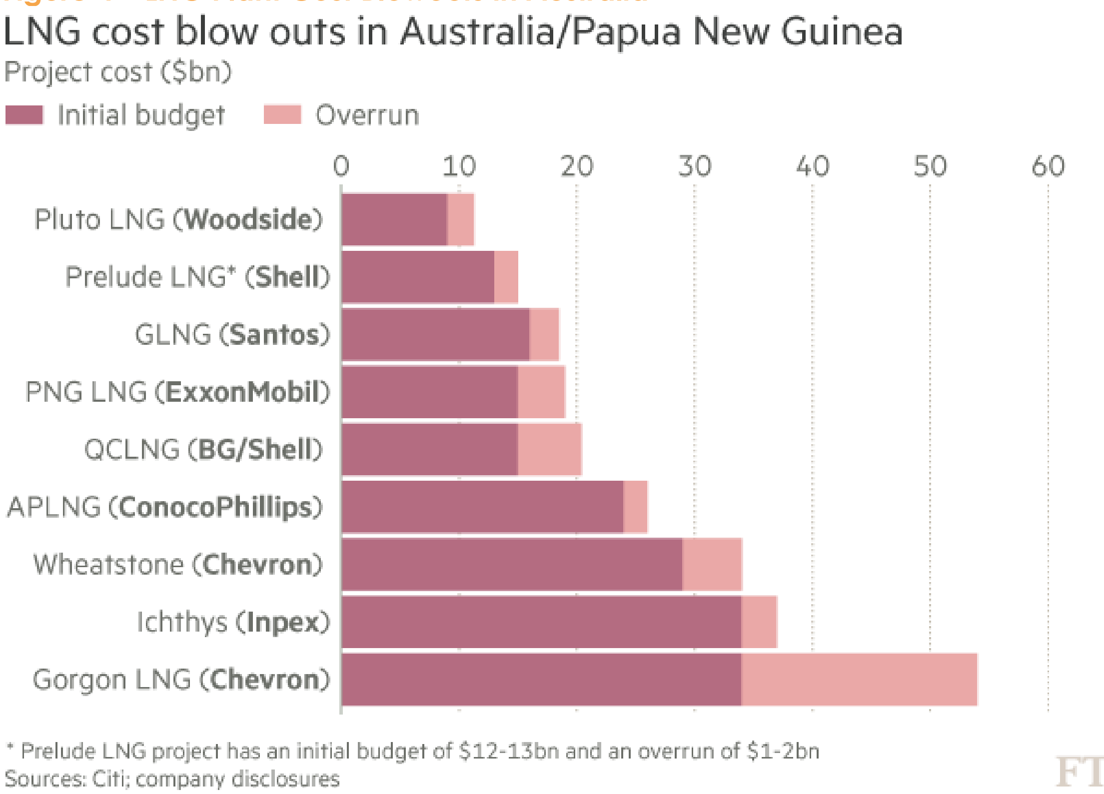
[26] http://www.businessdictionary.com/definition/delivered-ex-ship.html

The price of oil has fallen dramatically since many of the Gladstone contracts were signed, making it likely that any contracts with oil-price triggers are probably currently being renegotiated downwards.

Capital Cost of Plants at Gladstone

The three plants at Gladstone (GLNG, QCLNG and APLNG) are emblematic of the problem CEO Coleman described in his June 2016 remarks. All reported significant cost overruns and were late in delivery.

Figure 4 – LNG Plant Cost Blowouts in Australia



Source: https://www.ft.com/content/29667e96-9f15-11e6-891e-abe238dee8e2

Operating and Development Costs Were Underestimated for the Fields That Supply the Gladstone Plants

Operating and development costs for the Coal Seam Gas fields that supply the plants at Gladstone were vastly underestimated.

Note this estimate from Santos' Gladstone LNG (GLNG) Environmental Impact Statement (EIS):

> *"Morgan Stanley (2008) estimate that industry-wide operating and development costs for CSG are in the order of $2.20/GJ to $2.70/GJ, however as resource quality declines and recovery becomes more difficult, these costs are expected to increase, notwithstanding any technological break throughs."*[27]

And compare it with current CSG field costs, which range from $3.55 to $8.50/GJ (See Table 5 below). The cheapest field on the East Coast of Australia cannot produce gas even at the top end of estimated industry-wide operating and development costs.

Table 5 – Summary of Supply Costs ($A/GJ)

Basin	Low	Reference	High
Conventional			
Bass	4.46	4.05	3.65
Cooper	5.83	5.30	4.77
Gippsland	4.95	4.50	4.05
Otway	4.07	3.70	3.33
CSG			
Bowen - Fairview	4.95	4.50	4.05
Bowen - Moranbah/ATP 1003	7.70	7.00	6.30
Bowen - Spring Gully	3.90	3.55	3.19
Gloucester	5.45	4.95	4.46
Gunnedah	7.98	7.25	6.53
Surat - Eastern Walloons	6.70	6.00	5.70
Surat - IronBark	5.34	4.85	4.37
Surat - Middle Walloons	6.00	5.70	5.65
Surat - Undulla Nose	5.00	3.90	3.60
Surat - Western Walloons	9.35	8.50	7.65
Sydney - Camden Gas Project	4.46	4.05	3.65
Other Unconventional			
Cooper - Napamerri	8.65	7.75	6.80
Cooper - CBJV Unconventional	5.83	5.30	4.77

Source: Core Energy Group with Operator input for a number of areas.

Source: Gas Production and Transmission Costs – Core Energy/AEMO

[27] GLNG EIS Chapter 6 page 6.15.11

Operating and development costs in the average field on the East Coast of Australia are 145% higher than the mid-point of the expected range contained in Santos' GLNG EIS.

The problem for Gladstone plants it that the gas simply wasn't present in the quantities expected, production from the wells declined quicker than expected, and the wells produced more water than estimated. All of those factors led to much higher costs than expected.

Effects on the Domestic Market for Gas

The original "Blueprint for Queensland's LNG Industry"[28], published by the Queensland Governments Department of Employment, Economic Development and Innovation, clearly acknowledged that the development of the Queensland LNG industry might cause problems for the domestic market.

The Queensland public servants who authored the document recognized the potential for exports having a negative effect on domestic supply:

> "There is a real problem that the availability of gas in the ground may not translate into gas supplied to the domestic market."

The document went on to state:

> "Potential supply constraints are particularly problematic because gas is the most likely interim fuel for electricity generation as the economy transitions to low-emission power generation.
>
> It is clear that the Queensland Government must be sure there will be enough gas available to meet future electricity generation needs."

Policymakers suggested establishing either a domestic gas field reservation, where certain fields would be designated as domestic supply only, or implementing a domestic gas-reservation scheme.

Unfortunately, this was flatly ignored by politicians at both State and Federal levels and no scheme to reserve supply for the domestic market was forthcoming. The industry, instead, was given free rein to do as it pleased.

Perhaps the politicians were assured by gas industry promises that exporting gas would not affect domestic supply, a possibility that raises the issue of regulatory capture by APPEA as the revolving door between government and lobby groups spins. The group's CEO, Malcolm Roberts; its deputy CEO Noel Mullen; its COO; Steadman Ellis, and Director Matthew Doman all held senior government roles prior to joining APPEA.[29] The former Australian Resources and Energy Minister Martin Ferguson who crafted most of the regulatory and tax legislation for the gas industry now chairs APPEA's Advisory Board.

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[28] https://www.cabinet.qld.gov.au/documents/2009/aug/lng%20impacts%20review/Attachments/LNG%20Industry.pdf
[29] https://www.appea.com.au/about-appea/senior-management/

Santos asserted in the Environmental Impact Statement (EIS) for its Gladstone GLNG plant that it would not contribute to a future shortage of gas in the East Coast market:

> *"The project may initially supply domestic gas markets, but it is not diverting gas from local markets to export markets. The project's supply of gas to the domestic market is uncertain at this stage. Options to manage ramp-up gas and any gas that is surplus to the requirements of the LNG facility include a range of commercial and technical possibilities. Therefore the project has no direct implications for domestic gas prices. The gas to supply the LNG facility will come from newly developed CSG fields. The amount of gas is very small relative to the identified conventional and CSG fields reserves available to supply the Australian east gas fields. It is therefore unlikely to contribute to a future shortage of gas in the domestic market."* [30]

Santos made additional assertions that it could supply their export project from new sources of supply:

> *"As Santos worked toward approving its company-transforming Gladstone LNG project at the start of this decade, managing director David Knox made the sensible statement that he would approve one LNG train, capable of exporting the equivalent of half the east coast's gas demand, rather than two because the venture did not yet have enough gas for the second."*
>
> *"'You've got to be absolutely confident when you sanction trains that you've got the full gas supply to meet your contractual obligations that you've signed out with the buyers,' Mr Knox told investors in August 2010 when asked why the plan was to sanction just one train first up."*
>
> *"'In order to do it (approve the second train) we need to have absolute confidence ourselves that we've got all the molecules in order to fill that second train.'"*
>
> *"But in the months ahead, things changed. In January 2011, the Peter Coates-chaired Santos board approved a $US16 billion plan to go ahead with two LNG trains from the beginning."*[31]

Despite the official assurances by Santos both in approvals documents for the government and in investor briefings, the company has been unable to supply its export plants and is buying gas out of the domestic market instead.

Credit Suisse estimates that Santos is purchasing 160PJ out of the domestic market at present, equivalent to 27% of domestic consumption in 2016.[32]

The purchase of third-party gas for export is putting tremendous pressure on domestic prices.

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[30] GLNG Project - Environmental Impact Statement Chapter 6 Page 6.15.11

[31] http://www.theaustralian.com.au/business/mining-energy/how-santoss-leap-of-faith-became-gas-supply-strife/news-story/24fb1882347ac293f131f74b1255600b

[32] From Table 1 on Page 4 https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/NGFR/2016/2016-National-Gas-Forecasting-Report-NGFR-Final.pdf

Effects on the Domestic Prices for Gas

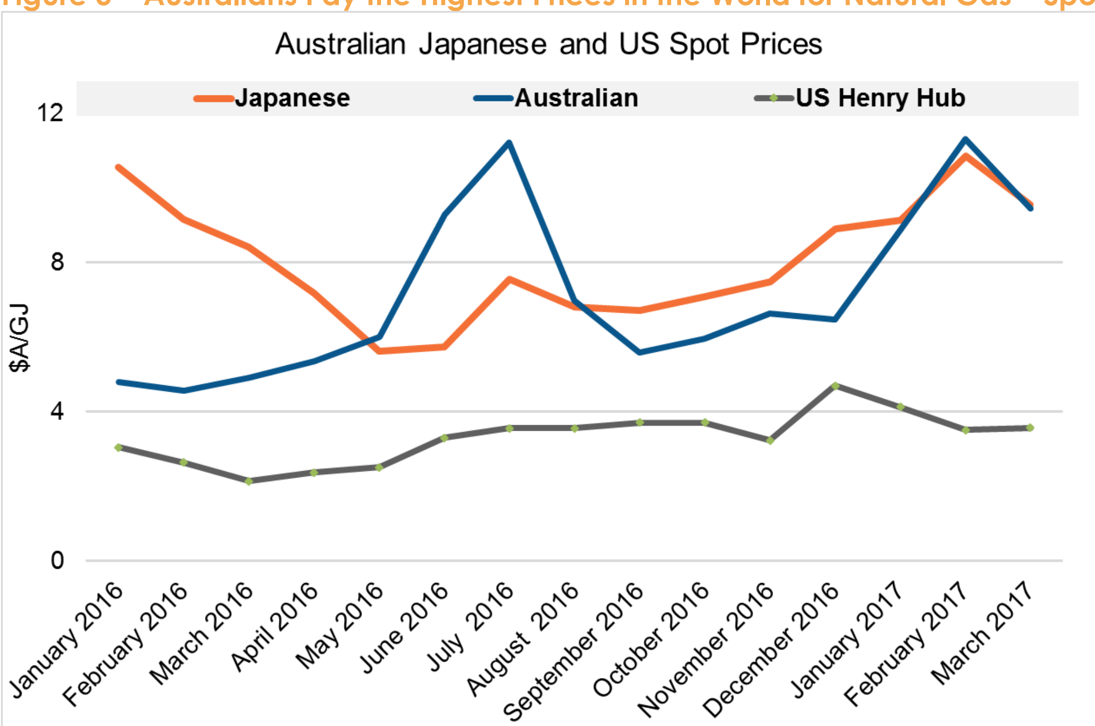
Australian domestic gas prices have now risen above global prices for both long-term contract gas and short-term spot gas.

The gas industry has said Australians are now paying "global" prices for gas, but nothing could be further from the truth. When making this assertion, industry officials often quote prices from the most expensive gas market on the globe, the north Asian market, as its benchmark "global" price.

For significant lengths of time, Australians have paid above the Japanese spot price for gas anyway, that is, more than the price of gas in the most expensive import market in the world. A more honest "global" price would reflect those reported in the U.S., where (Figure 5) consumers pay a fraction of what they pay in Australia.

When comparing the Japanese price to the Australian price of gas it must be noted that Australians, in fact, need not bear the cost of an expensive liquefaction process or of shipping LNG to Japan. Australian natural gas markets are supplied by pipelines tied directly to domestic fields. It costs around A$4.25/GJ to liquefy gas at the Gladstone plants and an additional A$0.70 to ship the gas to Japan. It stands to reason that Australians should be paying A$4.95/GJ less per GJ than Japanese customers do. This has not been the case for the last year, however, in fact in many instances the raw price in Japan has been substantially lower than prices in Australia.

Figure 5 – Australians Pay the Highest Prices in the World for Natural Gas – Spot Prices



Sources: Australian Energy Market Operator (AEMO), Ministry of Economy, Trade and Industry (Japan), US Energy Information Administration, Reserve Bank of Australia (RBA), IEEFA calculations.

Limited transparency means that contract prices for gas are difficult to ascertain. Japanese contract prices are tied to oil prices, specifically to the Japanese custom cleared crude price (JCC). The JCC is roughly equivalent to the international benchmark crude price for Europe Brent Crude. The reasons behind gas prices being linked to oil prices is historical; Japan used to generate electricity with oil-fired power plants, and when a substitute fuel, LNG, appeared Japan sought to price the two commodities similarly.

In Australia, data on gas markets is a closely guarded industry secret. The market in Eastern Australia is controlled by a four-player cartel: BHP/Exxon, Origin Energy, Santos and Shell. The cartel divulges as little information as possible and withholds supply to domestic spot markets, enabling it to control pricing into the domestic Australian market. The data we have on Australian Gas prices is from surveys undertaken by The Australian Industry Group (The Ai Group)[33] and from statements made by Rod Sims, Chairman of the Australian Competition and Consumer Commission.

Santos' in its GLNG EIS stated that from 2000-01 to 2007-08 gas prices increased at a rate of 2.7% per annum (i.e. below the general inflation rate). Gas prices were expected to rise to between $4.00-$6.00/GJ (ex-field) in the longer term, up considerably from 2014 prices of A$3-4/GJ.

From the Santos GLNG EIS:

> *"The growing demand for gas has, and is expected to continue to, place upward pressure on domestic gas prices. Eastern Australia domestic gas prices have already increased from around $2.60/GJ in 2000-01 to around $3.90/GJ in 2007-08 (VENCorp average spot market price). This is an increase in real terms of 2.7 % per annum. However, there is now considerable debate regarding future increases in the forward price, because of the expected increases in supply from the vast CSG resources in Eastern Australia. Various market analysts have considered demand, supply and cost factors and have put forward gas price forecasts for Eastern Australia. Forecasts from several of the most recognised market analysts presented in Figure 6.15.4 (Data compiled by Santos). The majority view seems to be that gas prices will increase from the current level of around $3.50/GJ to between $4.00/GJ and $6.00/GJ (ex-field) in the longer term."*[34]

However, prices are recently being offered to industrial consumers are $20/GJ, according to Rod Sims of the ACCC, in a media release dated 14 March 2017.[35]

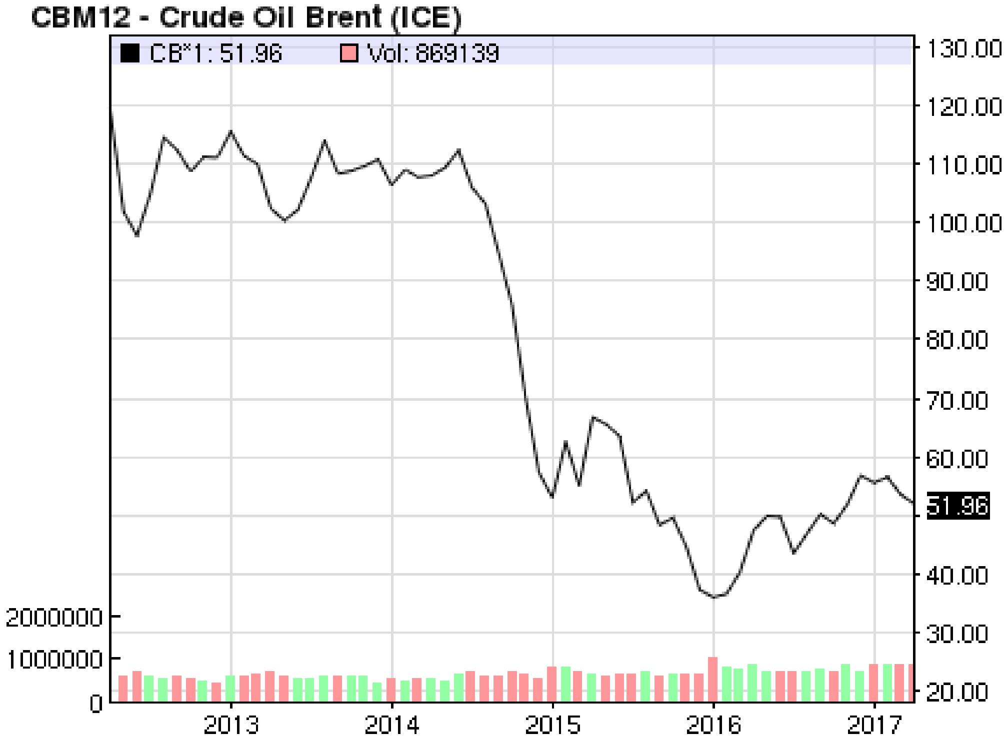
While the data is not robust, due mainly to the secrecy with which the gas cartel conducts its business, it clearly illustrates nonetheless that since the beginning of 2015 prices for Australian domestic gas have risen steeply, from A$3.50/GJ in 2014 to over $20/GJ. This is a far cry from the $4-6 long-term range forecast in Santos' GLNG EIS.

Australian manufacturing industries and consumers have worn this tremendous cost as a result of regulatory failure and gas industry manipulation.

By contrast, oil prices, which determine gas export prices, have halved since 2014.

[33] The Australian Industry Group, "Energy Shock: No Gas No Power No Future?", February 2017
[34] GLNG EIS Chapter 6 page 6.15.10
[35] Source: http://www.accc.gov.au/speech/recognising-australias-east-coast-gas-crisis

Figure 6 – Brent Crude Prices US$/bbl



Source: Nasdaq

Even with Australia domestic gas contract prices supposedly linked to global prices, contract prices for gas in Australia have relentlessly increased to levels unseen anywhere else in the world.

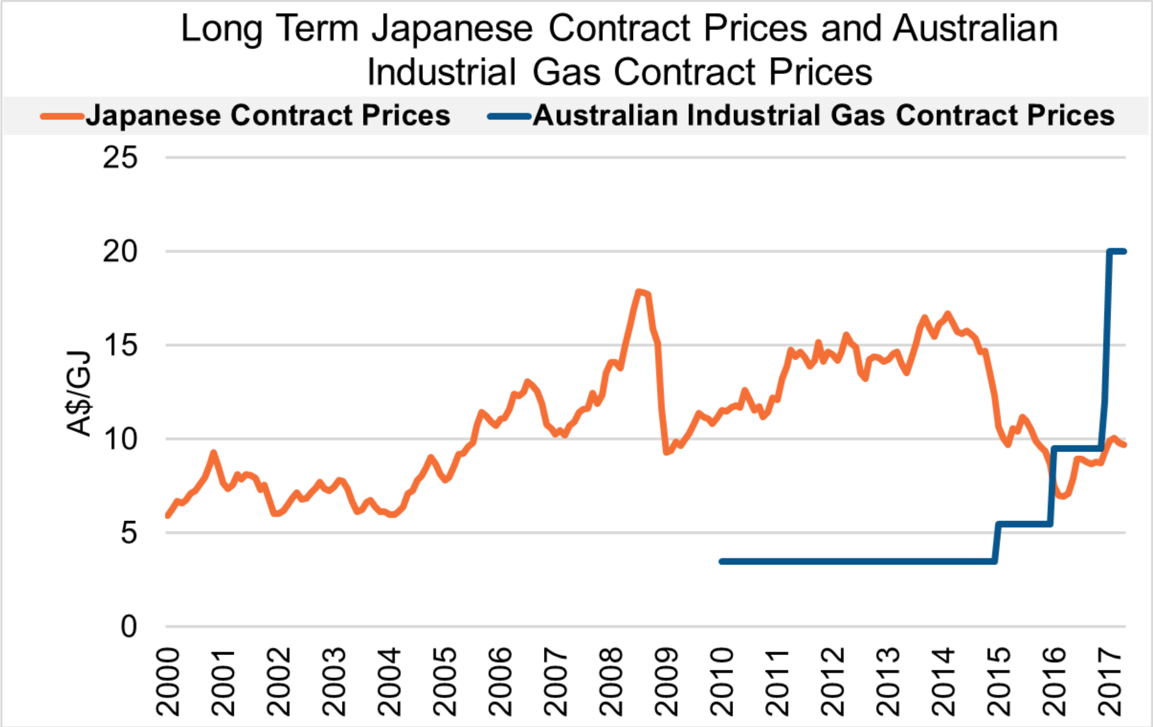
Further, Contract gas prices for Australian Industrial customers are now twice those of Japanese wholesale prices.

Recently (20 April 2017) Innes Willox, CEO of The Ai Group, suggested even that prices had risen further since February 2017 to levels some four times above those seen just two years ago:

> *"Gas prices are skyrocketing far beyond parity with export prices. While there is a lively debate about issues in the pipeline and retail segments and how to improve them, there has been no major change in those sections of the market that can explain the rise in gas prices offered to industry from around $6 a gigajoule two years ago to as much as $24 a gigajoule today."*[36]

[36] https://www.aigroup.com.au/policy-and-research/mediacentre/releases/Gas-Crisis-Progress-20April/

Figure 7 – Australians Pay the Highest Prices in the World for Gas - Contract Prices



Sources: Reserve Bank of Australia (RBA) Brent Crude prices, Australian Industry Group, IEEFA calculations

Write-downs to Date

All three East Coast Australian LNG export facilities at Gladstone have taken large capital write-downs.

BG Group wrote $5.4 billion off the value of its QCLNG project in early 2015.[37] The project had extensive delays and cost overruns, with an original budget of US$15bn blowing out to US $22bn.[38]

Santos has written down the value of its GLNG investment by $2.6 billion pre-tax.

Origin wrote down the value of its APLNG investment by $1.5 billion pre-tax in December 2016.[39]

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37 http://www.couriermail.com.au/business/bg-blames-oil-price-collapse-for-massive-writedown-on-its-qclng-project-in-gladstone/news-story/11c160372b751e375dfc7dddc09c9862

38 http://www.theaustralian.com.au/business/companies/triple-whammy-sparks-5bn-blowout-for-bgs-gladstone-project/news-story/e479789e31831828ff3a86833000ecac

39 Origin Energy - Interim Result December 2016 page 23

Table 6 – Capital Costs & Capacity of APLNG, GLNG& QCLNG relative to Cheniere's Sabine Pass

Comparison of Capital costs and capacity of APLNG, GLNG and QCLNG and Cheniere's Sabine Pass				
	($A m)	($A m)	($A m)	($A m)
	QCLNG	APLNG	GLNG	Sabine Pass T1-5
Capacity (MTPA)	8.5	9	7.8	22.5
Total Project Cost	29,626	25,900	24,912	23,566
Valuation per MT pre writedowns of plants at Gladstone	3,485	2,878	3,194	1,071
Source: Origin results, Santos results (ASX releases) Reserve Bank of Australia, Cheniere 10Q 30 June 2016				

The table above highlights the extreme difference in valuation per million tonnes of capacity between those plants built at Gladstone and the U.S. Cheniere's Sabine Pass facility. Cheniere appears to have built its plant far more efficiently and far cheaper. Its cost per million tonnes of capacity is under $1.1 billion/MT of capacity compared to the Australian plants which had original capital costs (pre-write downs) of between $2.9 to $3.5 billion/MT of capacity.

If we take Santos as an example, we see that in total it wrote off A$ 1.7 billion[40] over 2014 and 2015 its plant and equipment at GLNG. Assuming its partners wrote off a similar amount, the project is now valued at $19.3 billion. This gives a written down value per MT of capacity of $2.5 billion, some $1.4 billion above Cheniere's Sabine Pass. If GLNG wrote down its assets to comparable global asset values it would take a write-off of $10.9 billion. Santos for its 30% shareholding would write-off up to A$3.3 billion.

Origin Energy would face similarly large write-offs of its share in APLNG.

The ramp-up in production at Santos' GLNG facility has been substantially slower than expected and has led to a US$1.5bn pre-tax write down in August 2016.[41] Santos expects that it will take three years to ramp up production to 6MTPA, some 23% below nameplate capacity.[42] GLNG produced just 1.4MT in the first quarter of 2017. The lower-than-expected production combined with sustained low oil prices may lead to further write-downs in the value of the project.

The asset values on Santos' balance sheet are very sensitive to either a changed oil price outlook or rises in interest rates. Santos has large increases in U.S, dollar oil price forecasts for 2017 and further out.

Table 7 – Oil Price Forecasts by Santos, Origin Energy and the Office of the Chief Economist

	2017	2018	2019	2020	2021	2022
Santos	60	70	80.77	82.79	84.86	86.98
Origin	59	59	69	74	77	78.6
Office of the Chief Economist	56.3	58.6	62.3	66.6	69	71.5

40 Page 82 Santos Annual Report 2015, Page 78 Santos Annual Report 2016 using RBA exchange rate of USD 0.7236
41 http://www.theage.com.au/business/energy/santos-takes-us15b-writedown-on-value-of-glng-project-20160814-gqsg6g.html
42 Page 19 Santos 2016 Annual Report

It is instructive to compare the oil price assumptions that two very similar ventures use.

Santos has an oil price of US$86.98/bbl in 2022 compared to Origin Energy's US$78.6. Major variations like these will inevitably lead to large variations in assessed asset values. One wonders how auditors sign off on the accounts as a "true and fair view" when there are such material differences in asset values between Australian peers.

Comparisons with Official Government Forecasts

Bearing in mind that Origin's oil price forecasts are below those of Santos's, the official figures forecast by Australia's Office of the Chief Economist are well below Origin Energy's.

In 2022, official forecasts are some US$7.10 below those used by Origin and over US$15 below those used by Santos.

Implications of Changes in Oil Price Assumptions on the Santos Balance Sheet

Companies' assessed values are sensitive to changes in oil price, discount rates and currencies.

Taking Santos as an example:

If oil prices fall by US$5/bbl in all years, the value of GLNG declines by US$439m, and if the discount rate rises by 0.5%, the value of GLNG declines by US$189m.[43]

Oil is trading in the US$50/bbl range, over US$9 below the assumptions for 2017. Global interest rates are widely forecast to increase over the coming 12 months, which may lead to higher discount rates being applied.

If Santos used official Australian government forecasts made by the Office of the Chief economist, write-downs of over US$ 1 billion would need to be made to its GLNG venture.

It would appear that investors in Origin and Santos can look forward to further material write-downs in Santos' GLNG venture and in Origin's APLNG joint venture.

[43] Page 79 Santos Annual report December 2016

The Need for Integrity in Oil and Gas Company Accounts and Better Disclosures

IEEFA has recommended that policy makers hew to a consistent oil price deck and that consistent currency and discount rate assumptions be used in oil and gas company accounts.

This is a simple goal to achieve and would give some integrity to oil and gas company accounts in Australia.

In the U.S., the Securities and Exchange Commission (SEC) mandates a price on which reserves are calculated every year. The SEC price is the average of oil prices on the first day of the month of the previous 12 months.[44]

The SEC on reserve calculations:

> "The definition states that the economic producibility of a reservoir must be based on existing economic conditions. It specifies that, in calculating economic producibility, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first day of the month price for each month with the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions."[45]

Disclosure like those required in the U.S. enable informed comparison between all companies operating in the oil and gas industry—and they serve policy makers, regulators and investors. As the U.S. approach does not rely on existing conditions, it is not subject to forecasting errors and variability as is on display in Table 7 above, and the price is smoothed by taking 12 months of price data.

The SEC also insists on full disclosure on a consistent basis of both production from each oil and gas field and average production costs.

The Securities Act Industry guidelines on this point state that:

1. For each of the last three fiscal years by the same geographic areas for which production data are required by Statement of Financial Accounting Standards (SFAS) No. 69.

    i) the average sales price (including transfers) per unit of oil produced and of gas produced;

    ii) the average production cost (lifting cost) per unit of production. [46]

[44] http://www.theaustralian.com.au/business/wall-street-journal/sec-rules-kill-buzz-of-rising-oil-price/news-story/7096a4e13b60036f46c1665180840078

[45] Page 12 https://www.sec.gov/rules/final/2008/33-8995.pdf

[46] Page 2 https://www.sec.gov/about/forms/industryguides.pdf

Consistent and comprehensive disclosure like this would greatly aid the formulation of government policy on energy issues in Australia.

In Australia, for large resources such as the Bass Strait oil fields, there is virtually no public information on reserves, resources, average sales prices and average production costs. The Bass Strait is not deemed material for BHP and Exxon in a global context and hence basic information on it is unreported. Such disclosure would be mandatory in the U.S.

As a consequence of poor disclosure by oil and gas companies, the Australian public has been subjected to a rolling public-relations campaign that occurs prior to every approval process for a controversial gas project.

The industry has been successful in selling the "gas supply cliffs"[47] [48] story, which was promoted prior to AGL attempting to gain approval for the Gloucester Gas project, and more recently by the industry-sponsored Australian Energy Market Operator (AEMO) prior to Santos seeking approval for its controversial Narrabri CSG project. The latter supposed shortfalls in fact lasted only 11 days[49] before the AEMO realised that the tiny shortfall that was forecast was in fact non-existent.

Poor disclosure in the oil and gas industry is leading to poor policy decisions in Australia. It is not possible to produce good policy outcomes in the current information void.

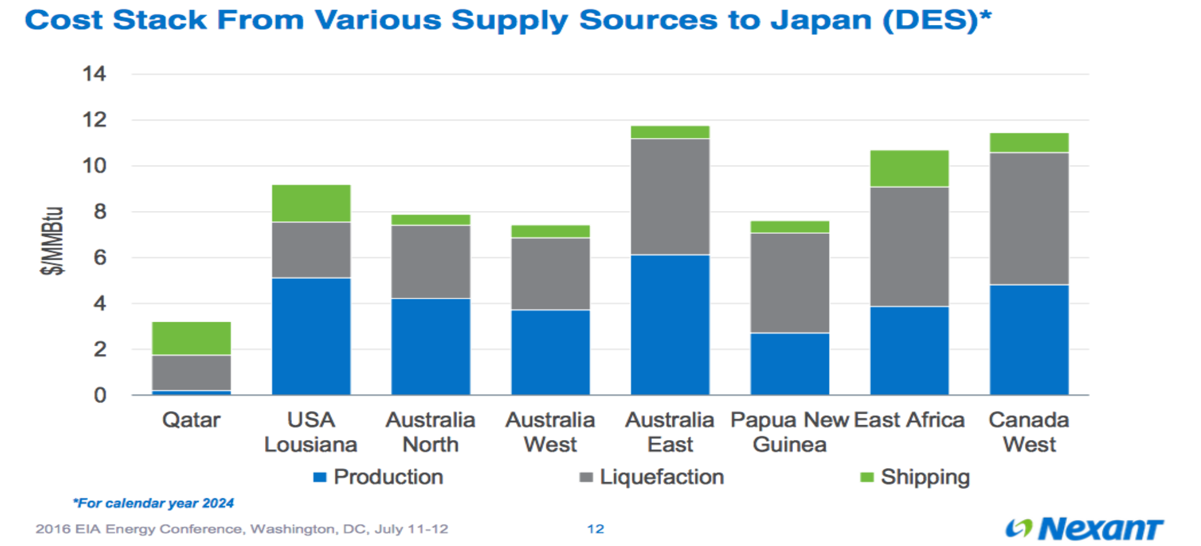
[47] AGL – Solving for "x" the NSW gas Supply Cliff – March 2014.

[48] http://www.smh.com.au/business/comment-and-analysis/no-need-to-fear-agls-gas-supply-cliff-20140320-354bb.html

[49] Page 4 http://climate-energy-college.org/short-lived-gas-shortfall

The Three Gladstone Plants Are the Costliest in the World

Figure 8 – Global LNG Cost Comparison



Source: http://www.eia.gov/conference/2016/pdf/presentations/mikhaiel.pdf

After any resources boom—and the LNG boom in Australia was one of the biggest in recent history—the highest-cost producers are typically the ones to exit the market before the market can find equilibrium.

As shown in Figure 8, the three plants at Gladstone are at the top of the global cost curve. With the global glut of gas continuing to expand out to 2020 it is likely that they will have to shut in some capacity at some point. Santos' Gladstone LNG plant is already operating its two trains at levels well below capacity.

New Sources of Supply for the Gladstone Plants

Three domestic sources of new gas supply are being contemplated to feed the Gladstone plants: Santos' Narrabri project; the Northern Territory Shale gas fields; and a pipeline to connect the east coast with gas field in western Australia.

Separately, a proposal has been made to supply the east coast market via an import terminal.

It is clear that the three domestic sources are not economic in a global market that faces an unprecedented glut and sustained low prices. The import terminal would permanently embed the cost of liquefaction and transport to Asia in the Australian domestic price. Australian consumers do not need to consume LNG, as there are ample supplies of domestic gas that can be supplied at a cheaper price.

Current Reserves on the East Coast of Australia

The Australian gas cartel has been very successful at restricting supply to the domestic market and forcing up the price. There is plenty of supply and plenty of reserves on the East Coast of Australia. Australia will be the world's largest exporter of LNG by 2021.

Table 8 – Gas Reserves and Resources by Basin

Basin	2P Reserves	3P/2C Reserves and Resources	Prospective Resources	Total Reserves and Resources
Conventional				
Adavale	22	22	-	22
Bass	221	512	-	512
Cooper and Eromanga	1,793	4,855	3,571	8,426
Denison	18	88	-	88
Gippsland	3,528	5,676	7,910	13,585
Otway	719	1,048	-	1048
Surat and Bowen	97	309	-	309
Sydney	0	-	13,992	13,992
Subtotal Conventional	**6,398**	**12,508**	**25,473**	**37,981**
CSG				
Clarence Moreton	17	12,367	3,816	16,183
Cooper and Eromanga	-	-	38,852	38,852
Denison	63	448	-	448
Galilee	-	313	4,413	4,726
Gloucester	527	649	-	649
Gunnedah	799	-	48,684	48,684
Surat and Bowen	44,622	91,502	27,155	118,657
Sydney	103	2,193	19,403	21,596
Subtotal CSG	**46,130**	**107,472**	**142,323**	**249,795**
Other Unconventional				
Cooper and Eromanga	5	6,652	162,910	169,562
Gippsland	-	762	-	762
Otway	-	-	11	11
Maryborough	-	-	20,140	20,140
ATP 855	-	-	26,866	26,866
Subtotal Unconventional	**5**	**7,414**	**209,927**	**217,341**
Total	**52,533**	**127,394**	**377,723**	**505,116**

Source: Core Energy Group

Source: Gas Reserves and Resources Eastern and South Eastern Australia- February 2015 – Core Energy/AEMO

The annual demand from the Eastern states of Australia is 590 petajoules a year (PJ/a). This compares with 1,290 (PJ/a) of gas now flowing to the plants on Curtis Island for conversion to LNG for export. Exports out of Gladstone are forecast to increase to 1,430 PJ/a by 2021.[50]

As can be seen in the table above, there are ample supplies for the domestic market for the foreseeable future. Conventional gas reserves and resources total 37,981PJ, enough to supply the domestic market on the East Coast of Australia for 64 years at current rates of consumption.

Gas consumption has been falling on the East Coast of Australia as gas-powered generation has been shut in due to declining cost-competitiveness (notwithstanding the resulting near doubling of domestic electricity prices), and demand is falling due to price gouging by the gas cartel.

Santos' Narrabri Project

Background

In July 2011, Santos acquired Eastern Star Gas for $924m. The Narrabri project in the Pilliga State Forest was the principal asset of Eastern Star. Santos then on-sold 20% of the Narrabri project to EnergyAustralia (formerly named TRUenergy) for $284m. At the time, Santos was emphasizing its access to the Gladstone export markets:

> "Santos access to Wallumbilla infrastructure enables entry to LNG export projects at Gladstone."[51]

Australia's Deputy Premier, Andrew Stoner, signed a memorandum of understanding with Santos in February 2014 designating Narrabri a "strategic energy project" and guaranteeing a final project—approval decision by Jan. 23, 2015.[52] Santos, however, did not lodge an Environmental Impact Statement and so the fast-track approval lapsed.

In February 2015, Santos wrote down the value of the Narrabri project by $808m pre-tax, citing a restatement of reserves. Reserves fell by approximately 30%. Like many East Coast Australian Coal Seam Gas fields, reserves at Narrabri were far lower than initial estimates, which were too optimistic.

Also in February 2015, CLP group (EnergyAustralia's HK parent) wrote off $355m pre-tax[53] from the Narrabri Project, its entire investment.

50 Table 1 page 4 https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/NGFR/2016/2016-National-Gas-Forecasting-Report-NGFR-Final.pdf

51 Page 8 https://www.santos.com/media/1877/180711_investor_presentation_acquisition_of_100_percent_of_eastern_star_gas.pdf

52 http://www.smh.com.au/environment/nsw-government-to-fasttrack-santos-coal-seam-gas-project-near-narrabri-20140221-337ge.html

53 Page 224 https://www.clpgroup.com/en/Investors-Information-site/Documents/Financial Report PDF/e_Annual Report 2014 (full version).pdf

In February 2016, Santos wrote down the Narrabri project by a further $588m pre-tax. The company cited the reclassification of its reserves from 2P to 2C, downgrading them from being commercial proven and probable reserves to non-commercial contingent resources.[54]

Santos now puts the value of the Narrabri Project at zero.

In total, Santos and its partner EnergyAustralia wrote off over $1.7billion dollars pre-tax on the Narrabri project—a project that has yet to deliver 1 GJ of commercial gas.

In the June 2016 interim result following a write down of $4m at Narrabri, Santos stated that: "the impairment charges have arisen primarily as a consequence of the reduction or delay in future capital expenditure that diminishes or removes the path to commercialisation."[55]

Effectively, Santos was stating that it would not be spending money on the Narrabri project to progress it to the production stage.

On Dec. 8, 2016, Santos announced that the Narrabri project was placed in a special purpose non–core assets company,[56] suggesting that Santos is now looking to exit its investment in the Narrabri project.

On Feb. 1, 2017, Santos lodged its Environmental Impact Statement for the Narrabri gas field.

The Costs at Narrabri

As shown Figure 4, the costs at the well head at Narrabri are estimated to be $7.25/GJ by the Australian Energy Market Operator. This is 75% higher than gas delivered to the Henry Hub in the U.S. in April 2017.

Once extracted, Narrabri gas would have to be taken to Gladstone for export across one of the most expensive pipeline networks in the world.[57] It will cost around $3.50[58] to get the gas to Gladstone making the delivered cost $10.75/GJ. The gas must then be liquefied and shipped to Asia at a cost of approximately $4.95 taking delivered cost in Asia to $15.79/GJ. In its first quarter of 2017 Santos reported a realised price for LNG sales of $8.86/GJ.[59]

Santos is currently exporting gas at a price some 78% below the cost at Narrabri.

As Santos itself has discovered the Narrabri gas project is not economic.

The Environmental Impact Statement

The New South Wales Department of Planning is currently considering approving the Narrabri project.

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[54] Page 19 2015 Santos Full year results presentation
[55] Page 21 Santos interim result June 2016
[56] 8/12/16 ASX release "Santos announces new strategy" page 16
[57] http://www.michaelwest.com.au/its-a-gas-australian-gas-prices-are-a-bargain-in-japan/
[58] Gas Production and Transmission Costs – Core Energy/AEMO
[59] Page 3 - utilising an exchange rate of 0.7583
https://www.santos.com/media/3600/170420_2017_first_quarter_activities_report-final.pdf

Narrabri represents all that has been done badly by both the industry and government in the Australian Gas industry in recent years.

The Australian gas industry as a whole has proceeded in the wrong order:

1. Signing exports contracts.
2. Getting government approval to build an export industry (without government assurance of a domestic supply in this process.
3. Building multi-billion dollar plants concurrently with rushed planning and poor execution, leading to major cost over runs.
4. Seeking to prove up a gas resource that in the end did not exist in the form expected.
5. Undersupplying the domestic market, causing gas prices to inflate to levels that is sending industry offshore and leading to higher domestic electricity prices.

The government and Santos are now repeating the exact mistakes made at the outset of the CGS-to-LNG export industry.

With Narrabri, Santos and the NSW government are attempting to get a project approved that:

1. According to Santos itself does not have an economic resource (Narrabri does not have 1 GJ of proven or probable reserves).
2. Is currently worthless; Santos and EnergyAustralia both have a "True and Fair" value in their accounts at $0.00 for the Narrabri project.
3. Has no current prospect of proceeding to the production stage given the stated accounts of Santos and EnergyAustralia.
4. Is currently for sale, which means that any undertakings given by Santos may not be honoured by future owners.
5. Lack any guarantee that the resource developed is for the domestic market (Santos is currently short of production for its export project, and the Narrabri gas will flow to exports).
6. Includes no gain for Australia, as it is high cost and if developed will increase domestic gas prices, not lower them.

The correct way to proceed with resource development is to prove up resources in the exploration phase, apply for a production licence and then produce.

If the NSW government approves Narrabri it is repeating the mistakes made, by both the industry and government, at the founding of the CGS-to-LNG industry. The project is not economic and should not be developed.

The Northern Territory

Introduction

The onshore gas industry in the Northern Territory is predicated on supplying the export LNG terminals at Gladstone in Queensland and/or the East Coast Australian domestic gas market.

The export gas terminals at Gladstone are currently loss-making and face significant economic challenges in the short, medium and long term.

Costs of production in the Northern Territory are estimated to be around A$7.50/GJ. The onshore unconventional gas industry has consistently underestimated its costs. Even taking this figure at face value and adding pipeline transportation costs, it is not possible to see how this is economic in a low-cost gas world.

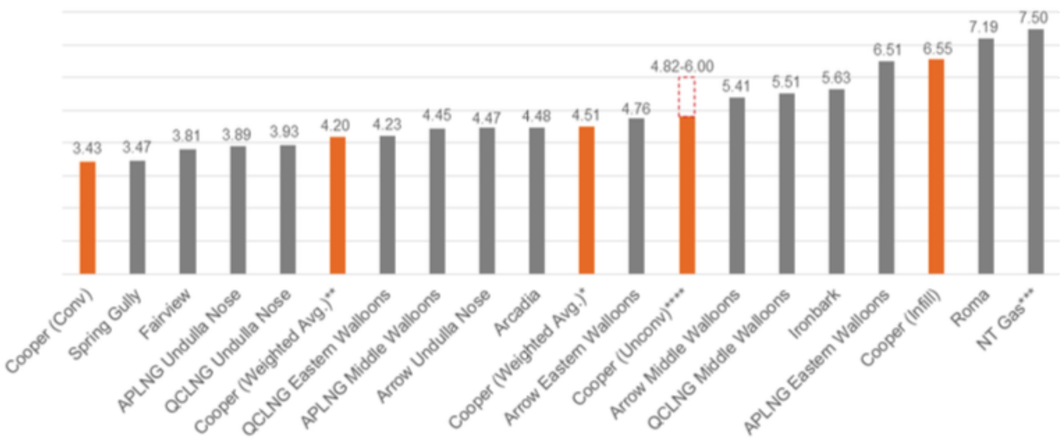
There is significant risk that if the industry proceeds in the Northern Territory, its assets will become stranded as export customers look to lower cost sources of supply and domestic gas consumers look to fuel switching to electricity. Instead of using gas to heat homes, for hot water and to cook with domestic consumers are finding it cheaper to abandon their gas connections and use electricity.

Costs of Production of Northern Territory Gas

The onshore gas industry in Australia has consistently underestimated costs of production.

In the Northern Territory, production costs have been estimated at A$7.50/GJ[60] by Core Energy in a report commissioned by the South Australian Department of State Development's Energy Resource Division.

Figure 9 – Production Costs of East Coast and Northern Territory Gas Fields



Source: Cooper- Eromanga Basin Outlook 2015 – October 2016 – Core Energy Group

[60] http://petroleum.statedevelopment.sa.gov.au/__data/assets/pdf_file/0005/283919/Core_Energy_-_Cooper-Eromanga_Basin_Outlook_-_Final_-_Oct2016v1.pdf

It is likely that this estimate will also prove optimistic. Even taking the cost of production at face value of A$7.50/GJ, they do not compare favourably on a global scale. Comparing Australia with its two largest competitors, Qatar and the U.S, is instructive. In Qatar, gas production costs are extremely low, below A$0.20/GJ, whilst in the U.S. the delivered price to the Henry Hub market averaged A$4.15 in April 2017.

Delivered to a metropolitan market or to the Wallumbilla Hub, the price of Northern Territory gas blows out in excess of A$11/GJ. This is more than twice the cost of gas delivered to the Henry Hub in the U.S.

Table 9 – Delivered Costs of Northern Territory Gas

Gas Play	VTS[14]	Adelaide	Sydney	Wallumbilla	Mt Isa
Ironbark	8.03 plus NVI tariff	7.75	8.03	5.63	8.34
APLNG Eastern Walloons	8.91 plus NVI tariff	8.63	8.91	6.51	9.22
Cooper (Infill)	7.55 plus NVI tariff	7.27	7.55	7.45-7.95	8.36
Roma	9.59 plus NVI tariff	9.31	9.59	7.19	9.90
NT Gas	11.86 plus NVI tariff	11.58	11.86	11.76	9.05

Source: Eromanga Basin Outlook 2015 – October 2016 – Core Energy Group[61]

The Victorian Transmission System ("VTS") is the transmission network across Melbourne and rural Victoria. The NSW-Vic Interconnect ("NVI") is the transmission pipeline running between Victoria and NSW, connecting the VTS and the Moomba to Sydney Pipeline.

Current spot prices in Japan are less than A$7.50/GJ. [62] That is after the gas has gone through the expensive liquefaction and transport process, which costs around A$4.95/GJ. Total costs of Northern Territory gas would be over A$16/GJ (A$11.76/GJ as per table 9 plus A$4.95/GJ to transport and liquefy) delivered to Japan, more than twice the price currently being paid.

The current contract prices being realised in Asia can be gleaned from the latest quarterly report put out by Santos.[63] The company states a realised price for its LNG exports of $US7.09/MMBtu, which is equivalent to A$8.96/GJ. Total costs of Northern Territory gas delivered Asia would be over A$16/GJ. This is 78% higher than Asian-based customers are currently paying under long-term contracts.

Gas produced in the Northern Territory is currently not economic to export to Asia on either the spot markets or the contract markets. Gas from the Northern Territory is simply not economic.

61 page 19 http://petroleum.statedevelopment.sa.gov.au/__data/assets/pdf_file/0005/283919/Core_Energy_-_Cooper-Eromanga_Basin_Outlook_-_Final_-_Oct2016v1.pdf
62 Source: Nikkei Asian Review dated April 14 http://asia.nikkei.com/Markets/Commodities/LNG-spot-prices-plunge-in-Asia-on-supply-glut-concerns
63 http://www.asx.com.au/asxpdf/20170420/pdf/43hmd0h79z0h82.pdf

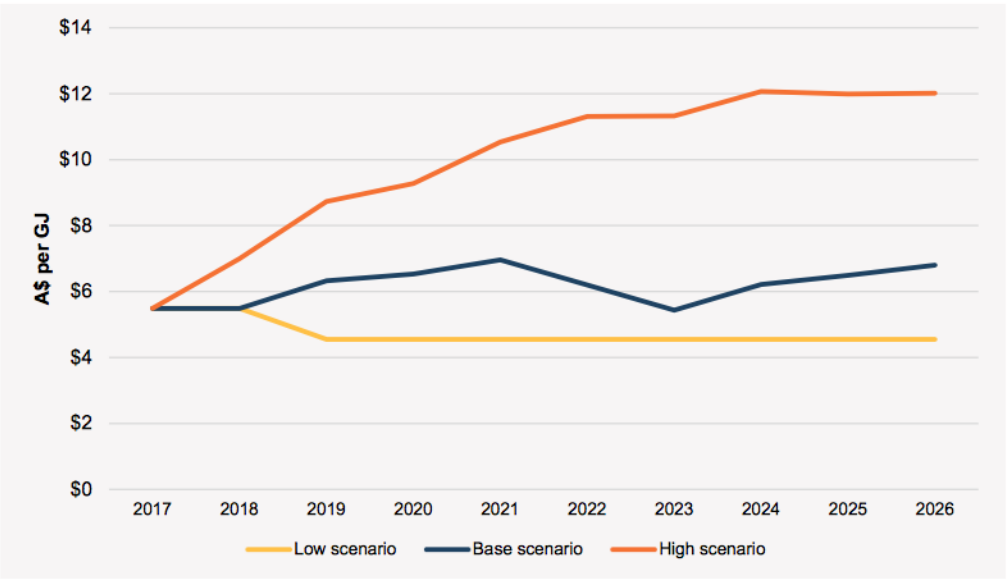
A Pipeline from Western Australia

A similar price analysis can be done for the idea of a pipeline from Western Australia (WA) to the eastern states. Currently domestic consumers are paying $6/GJ for contract gas in WA.

To get the gas to the eastern states would involve building a very long pipeline across the Nullabor. There have only been very approximate costings done on such a project of around $3-4/GJ. The landed price in the eastern states would therefore be around $9-10/GJ. This is above the price currently paid by customers in Japan for both contract and spot gas. Japan is the most expensive gas market in the world.

It is uncertain whether there are uncommitted quantities of gas available for such a project. The WA gas industry is very committed to exports, with long-term contracts signed, and is also committed to supplying its domestic WA customers under the Western Australian Government's successful domestic gas reserve policy.

Figure 10 - AEMO Forecast Medium to Long-term Average (Ex-plant) New Domestic Contract Gas Prices (Real), 2017 to 2026



Source: AEMO WA Gas Statement of Opportunities for Western Australia 2017- December 2016 – page 41[64]

An Import Terminal on the East Coast of Australia

The failure of energy policy in Australia to provide reasonably-priced gas to the domestic market is clearly illustrated by the proposal to build an import terminal on the East Coast of

[64] https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2016/2016-WA-Gas-Statement-of-Opportunities.pdf

Australia to supply the market. Two-thirds of East Coast Australian gas production is currently exported, and yet the Australian gas industry is unable to provide for Australia.

The domestic prices on the East Coast of Australia have risen to such a degree that AGL is seriously examining the possibility now of importing gas into a nation that will soon be the world's largest exporter of gas. It is akin to Saudi Arabia, the world's biggest exporter of oil, importing oil.

The $200-$300m import terminal would not start production until 2019, assuming AGL proceeds with the project.[65]

An import terminal would permanently embed costs of liquefaction and shipping to Asia in the domestic price. It would not lead to globally competitive domestic gas prices.

Conclusion

The three proposed expansions in potential domestic supply are all uneconomic. They all fail to acknowledge that the world is in a low-priced gas environment for the foreseeable future. All three proposals would supply gas at well above global prices. Likewise, the import terminal proposal is no solution to Australia's current domestic gas price crisis, as it provides gas to the domestic market at a price that includes the cost of liquefaction and transport to Asia.

[65] http://www.afr.com/business/energy/gas/lng-import-costs-questioned-as-agl-advances-terminal-project-20170406-gvfenu

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