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Prices and crisis:
LNG and Australia's East Coast gas market

Introduction

In 2017, a gas crisis emerged in Australia's East Coast gas market. Gas prices had increased rapidly from mid-2016 as the full effect of the three LNG projects starting operations on Curtis Island worked through the gas market, putting domestic energy users under pressure. In March 2017, the Australian Energy Market Operator (AEMO) forecast gas shortages in coming years, potentially leading to blackouts and industrial closures. While gas shortages are no longer forecast, challenges in the East Coast gas market remain.

This paper examines recent events in Australia's East Coast gas market, the challenges ahead, and the relevance of these developments for other countries.[1]

The paper identifies three phases in the East Coast gas market's recent history. Firstly, between 2010 and mid-2016, prices in the East Coast gas market rose gradually, driven by LNG netbacks and the rising cost of gas production. Then, between mid-2016 and mid-2017, prices climbed above export parity levels, as gas that was previously being supplied to domestic consumers (both by LNG projects and by other producers) was diverted for export, leading to a deterioration in competition in the domestic market. Finally, as of mid-2017, prices appear to have stabilised around export parity levels,[2] with LNG projects and other producers increasing gas sales to the domestic market.

The episode of high prices during much of 2016 and 2017 highlights the impact that LNG projects can have on domestic gas prices on Australia's East Coast. The paper therefore considers a number of possible scenarios in which LNG projects would have incentives to reduce supply to domestic consumers and increase purchases from third party domestic producers to support LNG exports. The paper concludes with a discussion of Egypt and Oman, which have also experienced domestic gas shortages following the start-up of LNG export plants, and have resolved these shortfalls through increasing domestic gas production and LNG imports.

The paper is divided into five sections. Section 1 provides an overview of Australia's East Coast gas market. Section 2 examines the drivers of recent gas price rises on the East Coast. Section 3 looks at the projections for a gas shortfall that were made in 2017 and the Australian Government's policy

[1] Nikolai Drahos was a visiting fellow at the OIES in early 2018, with support from the Department of Industry, Innovation and Science (DIIS) where he is based. The authors would like to acknowledge the contribution of David Whitelaw to the analysis presented in this paper.

[2] Domestic gas prices appear to have stabilized around netback prices from oil-linked LNG contracts, on which the majority of East Coast LNG is sold. However, at time of writing, domestic gas prices were substantially below netbacks from Asian LNG spot prices.

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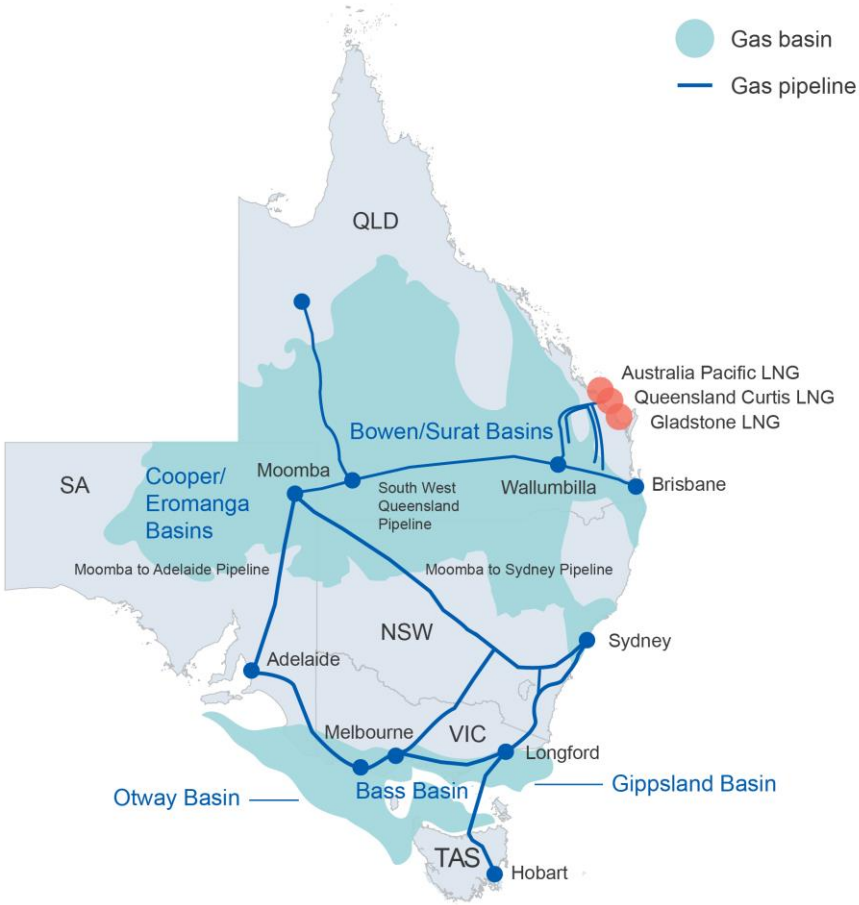
response, while Section 4 considers future challenges. Section 5 compares the Australian experience to similar episodes in Oman and Egypt.

Section 1: Background

This is the OIES' second paper on Australia's gas market. The first, *The Future of Australian LNG Exports*,[3] was published in September 2014, before LNG exports had commenced from Australia's East Coast. In that paper, the OIES argued that the start-up of LNG exports from Australia's East Coast gas market would see domestic gas prices rise towards export parity levels and potentially lead to domestic gas shortages. It noted that, unlike in Western Australia, there was no gas reservation policy[4] for the East Coast gas market.

Figure 1 shows Australia's East Coast gas market. The East Coast gas market can be thought of as consisting of a northern market (the North) and a southern market (the South). Queensland constitutes the northern market. The southern market covers Victoria, New South Wales, South Australia, Tasmania and the Australian Capital Territory. The Cooper Basin, located in southwest Queensland and north eastern South Australia, straddles the two markets.

Figure 1: Australia's East Coast gas market



Source: Department of Industry, Innovation and Science

[3] Ledesma, Henderson, Palmer, The Future of Australian LNG Exports: Will domestic challenges limit the development of future LNG export capacity?, NG90, September 2014, https://www.oxfordenergy.org/publications/the-future-of-australian-lng-exports-will-domestic-challenges-limit-the-development-of-future-lng-export-capacity/

[4] Also known as domestic market obligation.

Section 2: Evolution of the East Coast gas market

Historical arrangements

Gas was first delivered via pipeline to three state capitals in the East Coast gas market in 1969. For the next four decades, gas prices remained low. In the 2000s, before the first LNG project FID,[5] wholesale gas prices were around A$3-4/GJ (US$2-3/MMbtu). Industrial users, gas power generators (GPGs), and gas retail suppliers purchased gas on long-term contracts, reflecting the cost of production plus a margin. Non-price terms and conditions, such as provisions giving buyers flexibility on contracted volumes, were typically rolled over when gas supply agreements (GSAs) expired.[6]

Emergence of an LNG industry

Coal seam gas (CSG) was discovered in Queensland in the 1990s and its development accelerated in the 2000s. As the CSG industry developed, the huge scale of unconventional gas resources in Queensland became apparent. This led to interest from international oil and gas companies about the LNG potential of the region. An optimistic mood around Australia's CSG resources prevailed with cases of up to 13 LNG trains at Gladstone modelled.[7]

As international companies considered new LNG projects on the East Coast, oil prices, to which LNG prices are linked, were on the rise. At the same time, LNG demand in Asia was taking off. The outlook for gas demand seemed bright. Reflecting this, the International Energy Agency asked in 2011 whether the world was entering the 'Golden Age of Gas'.

FIDs for three East Coast LNG projects were taken over 2010 and 2011. A fourth two-train project, the Arrow LNG project, was also announced in 2010. The Arrow LNG project, however, did not come fruition. In the years that followed the LNG project FIDs, growth in global gas demand slowed, oil and LNG prices fell, and doubts about CSG reserves began to emerge.

The East Coast LNG plants

There are three LNG export projects on Curtis Island, near Gladstone, Queensland: Australia Pacific LNG (APLNG), Queensland Curtis LNG (QCLNG) and Gladstone LNG (GLNG). Figure 2 gives details of the projects. During construction all the projects experienced cost overruns and this, together with the fall in the oil price from over US$100/bbl when the FIDs were taken (most LNG exported by the three projects is sold on contracts under which the LNG price is linked to the price of oil), has created pressure on each project to improve its economics and to look at ways to reduce operating costs.

[5] Final Investment Date (FID): the date on which a project's sponsors decide to make a binding financial decision to proceed with the project. Usually the key agreements related to the project are signed on this date (e.g. plant construction, gas purchase, LNG sales and financing agreements). Also known as FID date.
[6] ACCC (2016), Inquiry into the East Coast gas market, p29.
[7] Bureau of Resources and Energy Economics (2014), Eastern Australian Domestic Gas Market Study, https://www.industry.gov.au/Energy/EnergyMarkets/Documents/EasternAustralianDomesticGasMarketStudy.pdf

Figure 2: Australia's East Coast LNG export projects

Plant	Owners	Capacity (mtpa)	LNG trains	Cost (US$b)	Start-up date (first LNG)	Long-term sales contracts	
						Buyer	Volume (mtpa)
Queensland Curtis LNG (QCLNG) FID: Oct 10	Train 1: Shell** (50%) CNOOC (50%) Train 2: Shell* (97.5%) Tokyo Gas (2.5%)	8.5	2	20.4	Train 1: Dec 14 Train 2: Jul 15 (first cargo)	Trains 1 & 2: CNOOC Shell*** Tokyo Gas JERA**** Total contracts [20 year contracts]	 3.6 3.3 1.2* 0.4 8.5
Gladstone LNG (GLNG) FID: Jan 11	Santos (30%) PETRONAS (27.5%) Total (27.5%) KOGAS (15%)	7.8	2	18.5	Train 1: Sep 15 Train 2: May 16	Trains 1 & 2: Kogas Petronas Total contracts [Kogas 15 years and Petronas 20 year contracts]	 3.5 3.5 7.0
Australia Pacific LNG (APLNG) FID: Jun 11	ConocoPhilips (37.5%) Origin Energy (37.5%) Sinopec (25%)	9.0	2	24.7	Train 1: Dec 15 Train 2: Sep 16	Train 1: Sinopec Train 2: Sinopec Kansai Electric Total contracts [20 year contracts]	4.3 3.3 1.0 8.6

* Includes 0.3 mt from the Shell portfolio

** Ex BG, acquired in 2015 when Shell bought BG

*** Shell has a portfolio supply deal with CNOOC for ~5 mtpa. Some of these volumes will come from QCLNG.

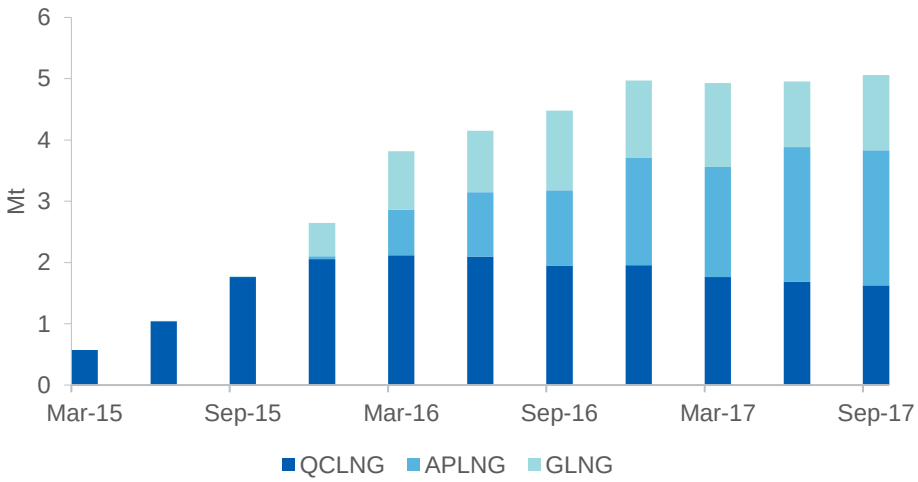
**** Original deal signed with Chubu Electric, now JERA

Source: South-Court research

QCLNG was the first export project to start production, followed by GLNG, then APLNG. APLNG has been producing at close to nameplate capacity in recent quarters. Average production at GLNG, however, remains well below capacity at just 5.2 mtpa in 2017 (66.6% of capacity).[8] As can be seen in Figure 3, QCLNG's production has fallen since mid-2016, a function of the weak Asian LNG spot market.

[8] LNG World News 25th January 2018

Figure 3: Production of LNG by East Coast projects, quarterly



Source: EnergyQuest

LNG sales structure

The sales of LNG from the three projects have been structured differently with regards to the proportion of long-term and short-term sales, which buyers are end-users of the LNG, and which companies will seek to onsell the LNG. Figure 4 shows the LNG sales from each of the three projects, concluding that around 15% of the LNG will be sold to portfolio buyers or on the spot market. Approximately half of that volume is estimated to be through Shell's capacity at QCLNG, which it acquired from BG as part of its 2015 company purchase and which forms a part of Shell's global LNG aggregator trading volume. It cannot be assumed that all of the aggregator volume will be sold on a spot or short-term basis[9] as companies such as Shell may well have committed part of this volume to term buyers. Likewise, all the term buyers may seek to sell some of the volume on a spot or short-term basis, particularly where the companies have equity in the project resulting in volumes of "equity" LNG that potentially give greater contractual flexibility than LNG purchased under long-term LNG contracts.[10] All the projects want to maximise revenues through these spot and short-term LNG cargo sales.

At nameplate capacity, the three LNG plants would export around 1375 PJ gas per year (34 bcm), with approximately 15% of the LNG being sold spot or through a portfolio company. It could be argued that the output of the plants could be reduced to just supply long-term contract buyers so as to free up gas to meet local demand. However, non-end user buyers, that have contracted for volume on a long-term basis, even though defined as "flexible volume", could well have sold some of that volume term from their portfolio so reducing LNG volumes may be difficult. It is assumed in Figure 4 that 1.5 mtpa of the Shell and 1.0 mtpa of the Petronas volume is sold on a short-term or spot basis. This means that at full plant operating capacity the pure spot element could be 15% LNG sales volume or 3.7 mtpa, equivalent to around 200 PJ of gas, which is significantly higher than the 34 PJ gas that the LNG exporters have advised the Australian Competition and Consumer Commission (ACCC) for anticipated LNG spot sales in 2018.[11] This must be because all the plants are not operating at full capacity and some of the portfolio/spot volumes are being treated as sales on a term basis.

[9] This paper defines short-term as contracts of less than 4 years duration and spot as contracts less than 3 months duration in line with the International Group of Liquefied Natural Gas Importers (GIIGNL) definitions.
[10] LNG purchased under long-term contracts would, in the 2010-2013 period when the sales agreements were finalized, have included destination restrictions and potentially other restrictive contract terms. If the project was structured to enable equity holders to take "Equity LNG", then this LNG would not normally have these restrictions.
[11] ACCC (December 2017), Gas inquiry 2017-2020: interim report, p11.

Figure 4: Australia's East Coast LNG Projects, structure of LNG sales (mt)

LNG project	Nameplate capacity	End User	Portfolio/ spot
Australia Pacific LNG (APLNG)	9.0	8.6	
Queensland Curtis LNG (QCLNG)	8.5	7.0	1.5*
Gladstone LNG (GLNG)	7.8	6.0	1.0**
Balance capacity			1.2***
Total	25.3	21.6	3.7
		85%	15%

Notes: In 2017 LNG sales from GLNG were only 5.2 mtpa (66.6% capacity).

Table assumptions:

* 1.5 mtpa Shell volume assumed to be traded as aggregator volume

** 1 mtpa of the Petronas volume assumed to be traded short-term

*** APLNG 0.4 mt & GLNG 0.8 mt

In its 2016 report the ACCC acknowledged that for contractual reasons it may be difficult for the LNG exporters to reduce LNG exports below contractual commitments, even in a low price environment. This is important as it confirms that contracted gas targeted for LNG exports cannot be diverted to the domestic market without financial penalties and an impact on the international reputation of the LNG supplier.[12]

The first phase: preparing for export

The recent history of Australia's East Coast gas market can be divided into three phases. In the first phase, wholesale gas prices in new GSAs rose in both the northern and southern markets,[13] starting from around the time the three LNG projects were commissioned in 2010 and 2011, as Figure 5 shows. The underlying drivers in the two markets, however, were very different.

Price rises in the north reflected the growing influence of international LNG prices on domestic gas prices.[14] LNG projects were able to pay up to LNG netback prices for domestic gas – the price of LNG minus the cost of transportation, liquefaction and transmission – and domestic consumers increasingly needed to compete on those terms. Expectations of LNG netbacks came to inform domestic contract price negotiations, although it is worth noting that the relationship between domestic prices and LNG netbacks remains imprecise.

Prices also rose in the southern market from 2010, but increases were initially more subdued than in Queensland. The ability of southern producers to sell their gas to international customers was constrained by the high cost of transporting gas to the North, as well as capacity and contractual limitations on pipelines.[15] LNG netbacks therefore did not exert the same pull over gas prices in the South.

[12] ACCC (2016), Inquiry into the East Coast gas market, p29.

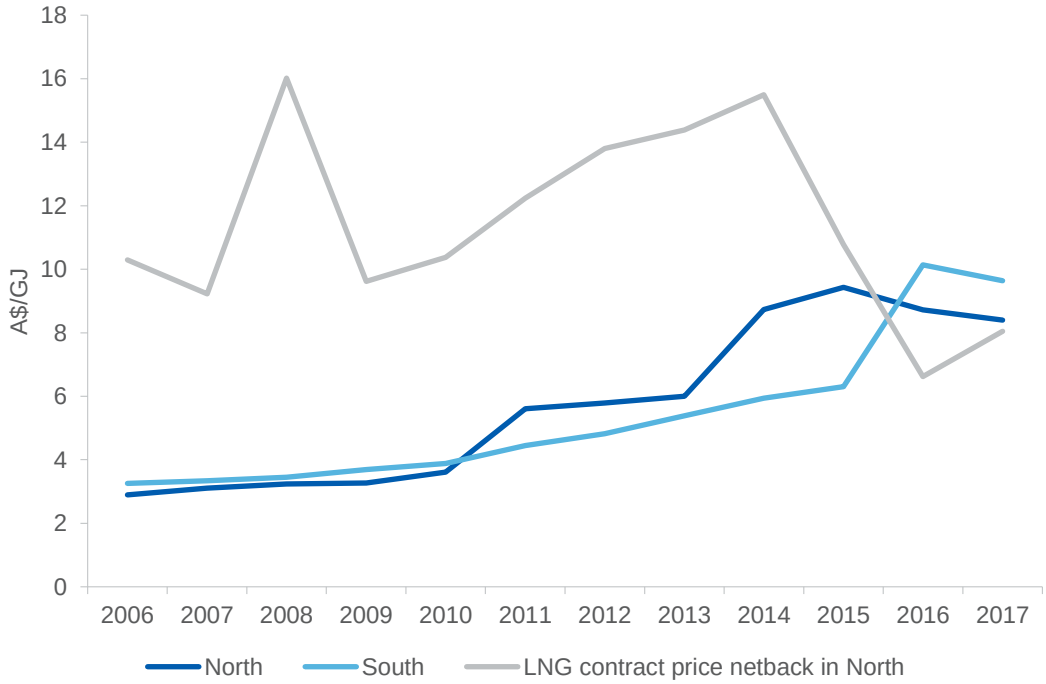
[13] Queensland constitutes the northern market. The southern market covers Victoria, New South Wales, South Australia, Tasmania and the Australian Capital Territory.

[14] ACCC (2016), Inquiry into the East Coast gas market, p32, p45.

[15] ACCC (2016), Inquiry into the East Coast gas market, p48.

Instead, gradual price rises in the South more likely reflected rising production costs from ageing fields in the Cooper Basin and the basins offshore Victoria, which supplied the southern market. Gas production in the Cooper Basin had gotten underway in the late 1960s. Rising production costs in the basins offshore Victoria were the result of an ongoing shift in production from high volume, shallow depth, high-quality gas fields to low volume, deeper, low-quality gas fields.[16]

Figure 5: Contract prices for large industrial users on new gas supply agreements: North vs South[17]



Source: Oakley Greenwood, author calculations

While prices increased, non-pricing arrangements in new GSAs also began to change.[18] New GSAs tended to be shorter in duration and buyers increasingly faced more restrictive conditions, such as the removal of rights that allowed buyers to carry forward unused daily quantities.

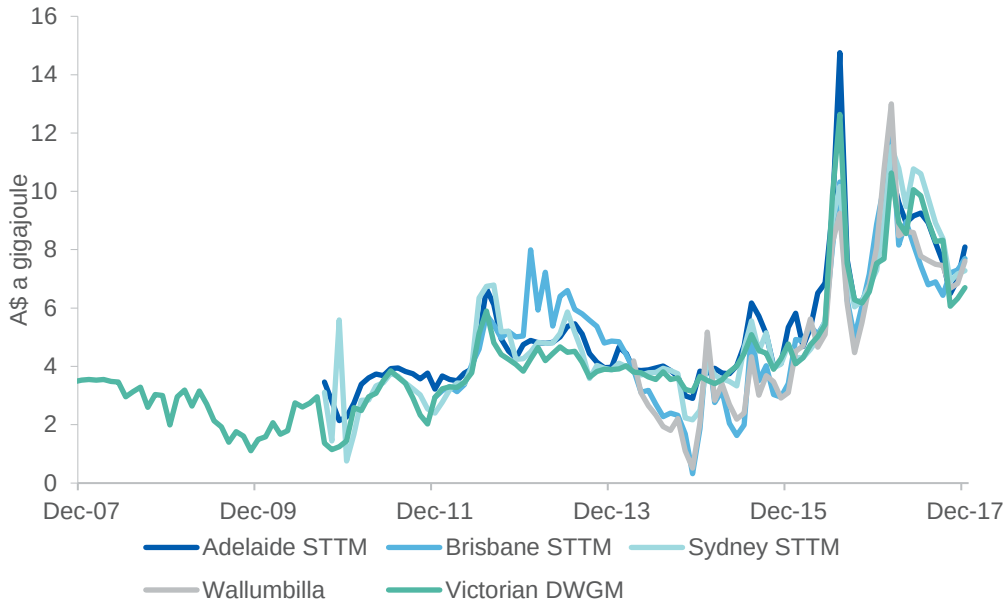
Like prices for new GSAs, domestic wholesale spot prices on the East Coast also started to increase around 2010 (Figure 6). However, unlike contract prices, spot prices declined in 2013 and remain low through to the end of 2015. These low spot prices reflected the increasing supply of 'ramp gas' - gas produced in the process of dewatering CSG wells that were being prepared to support future LNG exports. In sum, while contract prices rose from 2010, spot prices were pinned down by the dynamics of an emerging East Coast LNG industry.

[16] Department of Industry, Innovation and Science (November 2017), Offshore south east Australia future gas supply study, p6, p53.

[17] To calculate the oil-linked LNG contract price, the slope in Gladstone contracts was estimated at 14% of the JCC oil price. The netback was calculated at Wallumbilla, Queensland. The marginal cost of transmission from Wallumbilla to Gladstone was assumed to be zero, consistent with the ACCC September 2017 Gas Market Inquiry.

[18] ACCC (2016), Inquiry into the East Coast gas market, p18. ACCC (September 2017), Gas inquiry 2017-2020: interim report, p52.

Figure 6: Prices at gas trading hubs in the East Coast gas market, monthly



Source: AEMO

The second phase: price escalation

Prices increase above LNG netback levels

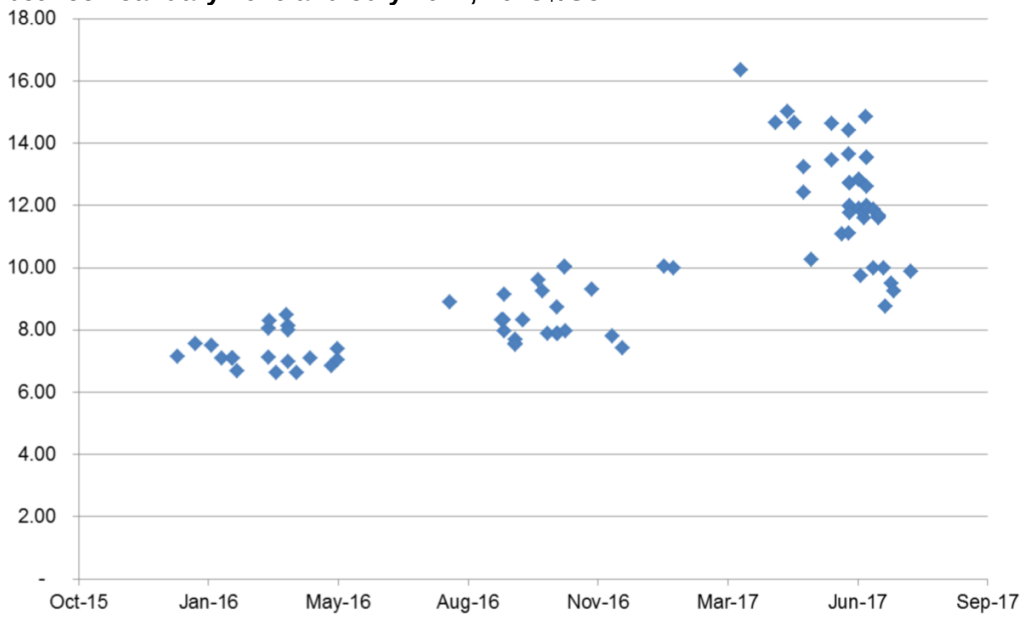
LNG exports from the East Coast commenced in January 2015. While prices for new GSAs and on domestic spot markets rose over 2015, increases were moderate. From mid-2016 through to mid-2017, however, prices escalated. As Figure 6 shows, wholesale spot prices at domestic trading hubs spiked in mid-2016 and then again in early 2017. Gas prices in new GSAs for large industrial customers also rose in 2016, increasing by around 30% to $9.60/GJ (US$7.60/MMbtu).

Figure 7 shows offers for wholesale gas supply in 2018, made between January 2016 and July 2017, which were not accepted by buyers (including retailers, commercial and industrial users, and GPGs) in the East Coast gas market. These were around A$6-8/GJ in early 2016 (US$5-6/MMbtu), A$8-10/GJ in late 2016 (US$6-8/MMbtu), and A$10-15/GJ in the first half of 2017 (US$8-12/MMbtu). Price offers to commercial and industrial users seeking less than 1 PJ of gas per annum were even higher, with offers of A$18-19/GJ in mid-2017 (US$14-15/MMbtu).[19]

It is difficult to explain these developments in terms of LNG netback pricing. Prices for new GSAs during 2016 and 2017 were above LNG netbacks (Figure 5), while in early 2017 domestic spot prices (Figure 6) and offers (Figure 7) were well in excess of export parity prices. The longer-term trend of rising production costs in the basins supplying the South also seems unable to explain this sudden price escalation. Figure 8 shows how prices on domestic spot markets spiked in mid-2016 and again in mid-2017, just after LNG trains on the East Coast began production, taking them above international spot prices.[20]

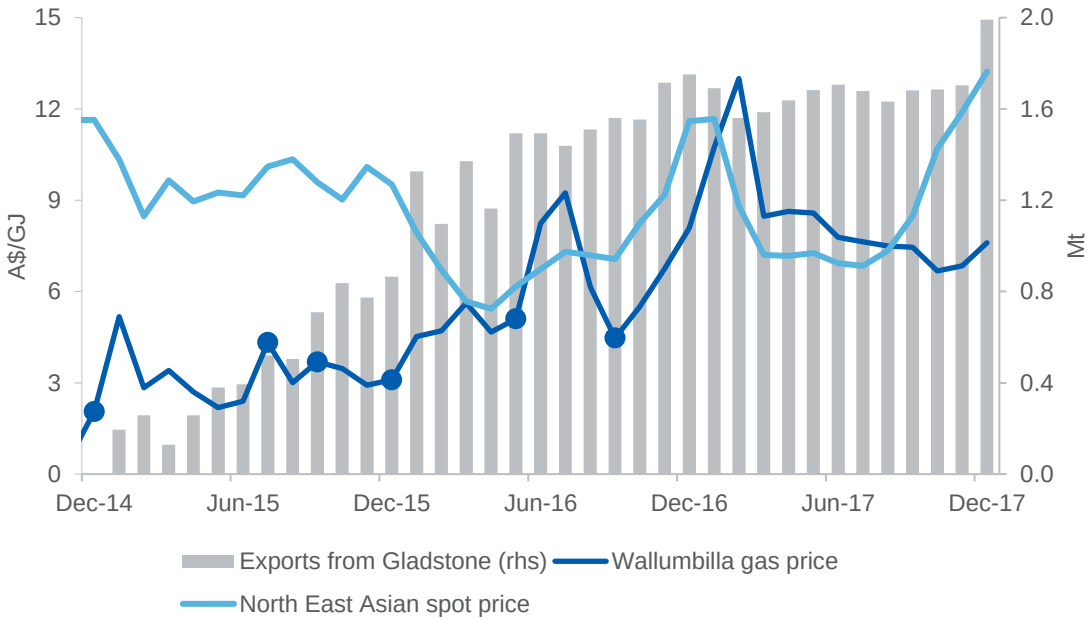
[19] ACCC (December 2017), Gas inquiry 2017-2020: interim report, p52.
[20] For an analysis of the relationship between domestic spot prices and LNG netbacks see Department of Industry, Innovation and Science (December 2017), Resources and Energy Quarterly, https://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Resources-and-energy-quarterly.aspx.

Figure 7: Unfulfilled offers of over 1 PJ per annum for wholesale gas in the East Coast gas market between January 2016 and July 2017, 2018$/GJ[21]



Source: ACCC September 2017 Gas Inquiry

Figure 8: Wallumbilla gas price, Asian LNG spot price and LNG exports, monthly[22]



Notes: blue dots represent first gas at each of the 6 East Coast LNG trains.
Source: Gladstone Ports (exports), AEMO (Wallumbilla price), Argus Media (LNG spot price).

[21] ACCC (September 2017), Gas inquiry 2017-2020: interim report, p75.
[22] The chart shows domestic spot prices at the Wallumbilla gas hub – the larger of the two gas trading hubs in the northern gas market. All domestic spot prices track closely, as shown in Figure 6.

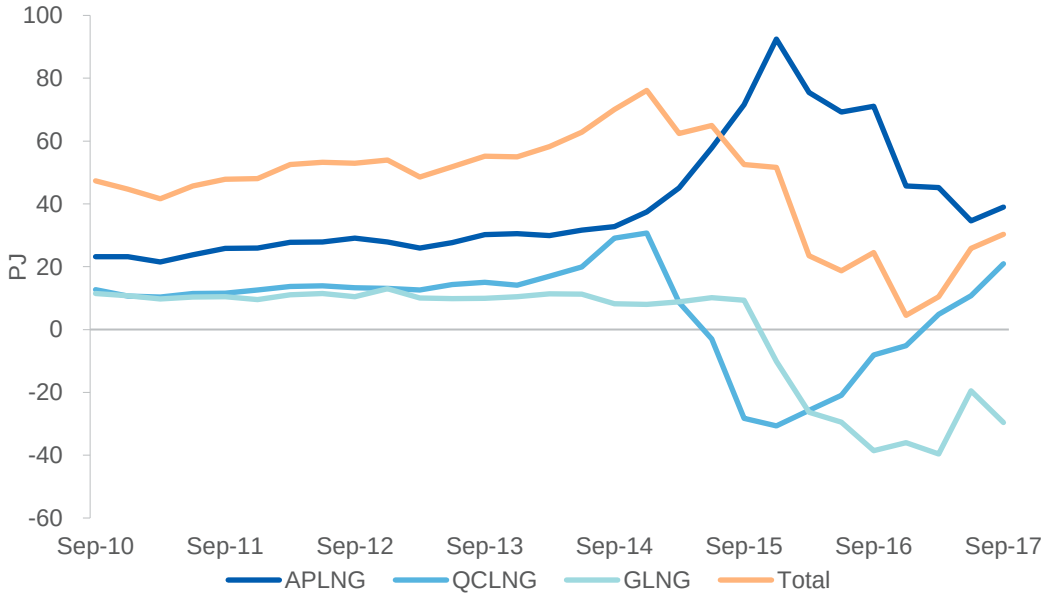
It is clear that conditions in the East Coast gas market changed quickly between mid-2016 and mid-2017. However, it is important to note that domestic spot prices and unfulfilled offers did not represent the prices being paid by most consumers. Indeed, with many buyers still on legacy contracts and those looking for new supply holding off on recontracting, the average wholesale gas price for all active contracts in mid-2017 was just A$5/GJ (US$4/MMbtu).[23] However, the question in mid-2017 was whether the price offers at the time represented the new norm.

The next section discusses the reasons for the sudden increase in prices and offers between mid-2016 and mid-2017.

The withdrawal of LNG project supply

For most of the five years prior to the start-up of LNG exports, the three LNG projects produced a combined total of around 50 PJ of gas each quarter and sold this gas into the domestic market. This supply by LNG projects to the domestic market ("LNG project supply") peaked in quarter four 2014, with CSG fields beginning production in advance of LNG exports starting in January 2015. Figure 9 shows the net contribution of gas from the three East Coast LNG projects to the domestic market, i.e. each project's total gas production minus its LNG exports and the gas used by that project in the liquefaction process.

Figure 9: Net contribution of LNG export projects to the domestic market, quarterly[24]



Source: EnergyQuest, author calculations

Although the amount of gas that the LNG projects sold to domestic customers gradually declined over 2015, they remained major contributors to the domestic market. Even at the end of 2015, LNG project supply to the domestic market was still at levels typical of the preceding five years. As Figure 9 shows, while QCLNG and GLNG began to purchase gas from the domestic market in 2015 (by exporting more than they produced), these purchases were largely offset by increased production at APLNG in the lead up to its first LNG shipment in early 2016.

[23] ACCC (September 2017), Gas inquiry 2017-2020: interim report, p63.

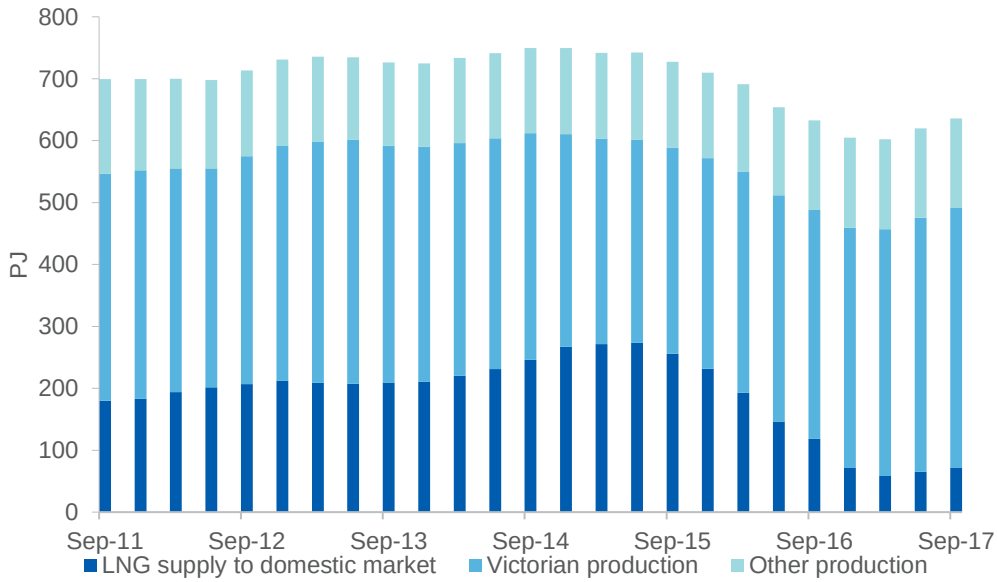
[24] An LNG project's net contribution to the domestic market equals its total gas production minus its exports and the gas it uses in liquefaction (LNG plant efficiency is assumed to be 8%). This method of calculating an LNG project's sales to domestic consumers does not take into account changes in the amount of gas an LNG project has storage.

In 2016 as LNG exports ramped up, the aggregate amount of gas LNG projects were supplying to the domestic market fell in a much more rapid manner, as the remaining three trains on the East Coast started operations. The net contribution of LNG projects to the domestic market bottomed out in quarter four 2016 - the very time that the price crisis in the East Coast gas market was taking hold.

This fall in the amount of gas LNG projects were, in aggregate, supplying to the domestic market was driven by an increase in LNG exports. In 2016, East Coast LNG exports tripled on 2015 levels to 17 million tonnes. To support increased LNG exports, APLNG reduced the amount of gas it supplied to the domestic market, while GLNG and QCLNG purchased gas from third party domestic producers. In both cases, gas that had previously flowed to domestic consumers was redirected for export.

While the net contribution from East Coast LNG projects was in decline, production stepped up in the East Coast market's second largest producing area – offshore Victoria. However, as Figure 10 shows, the increase in Victorian production was not sufficient to prevent a sharp contraction in the overall amount of gas produced for the domestic market.

Figure 10: Production for the domestic market, moving annual total[25]



Source: EnergyQuest, author calculations

A deterioration in competition in the South

Over 2016 and 2017, price rises were particularly pronounced in the southern market, as Figure 5 above shows. At a state level, prices were higher the further the distance, and therefore the greater the transportation cost, from Queensland, with Victoria and Tasmania experiencing the highest prices on the East Coast (Figure 11).

The sharp increase in southern prices was driven by a deterioration in competition in the South. The Cooper Basin, and to a lesser extent Queensland, had previously supplied the southern market, with gas flowing from north to south. Three things changed in 2016 as LNG exports ramped up. First, gas stopped flowing from Queensland to the southern market via the Cooper Basin. Second, some gas that had previously been flowing south from the Cooper Basin was redirected to export projects in

[25] Each quarter is the sum of the past four quarters. Total LNG exports have been subtracted from total LNG project gas production. However, in reality, LNG projects purchase some gas from third parties (for example, those captured in 'other production') and sell some of their own production to the domestic market. This measure of production for the domestic market does not capture changes in gas storage.

Queensland. Third, over certain periods during 2016 and 2017, the North imported gas from the South along the Moomba to Sydney Pipeline, directly competing with southern consumers.

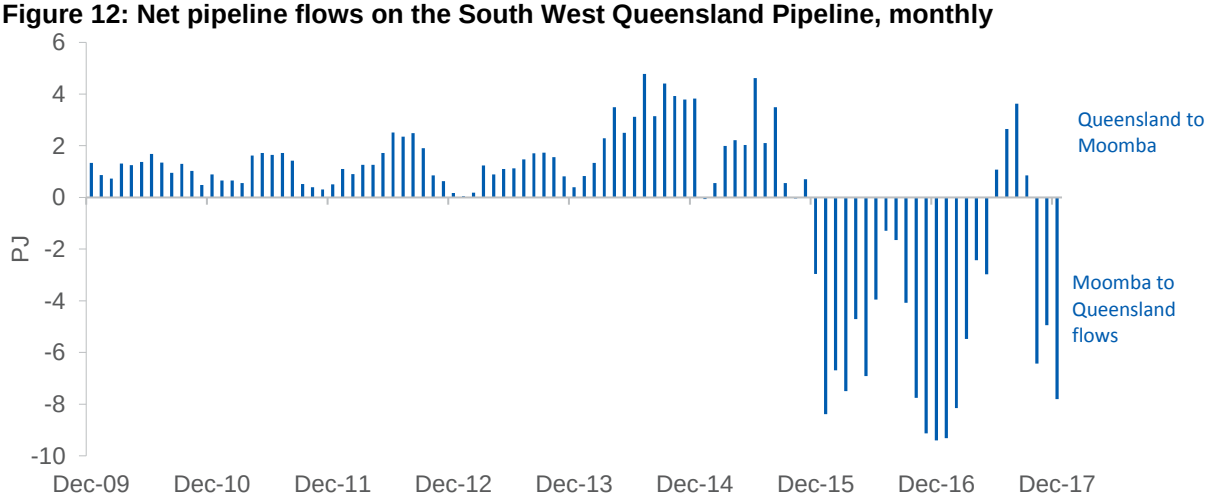
Figure 11: Contract prices for large industrial users on new gas supply agreements: 2015 vs 2017

Source: Oakley Greenwood

With supply from the Cooper Basin and Queensland reduced, and northern buyers even competing for southern gas at times, it is likely producers in the South had significant bargaining power in contract price negotiations with buyers. Buyers were particularly reliant on production from the Gippsland Basin, which accounted for over 75% of Victorian production and which was dominated by a single supplier: the Gippsland Basin Joint Venture (GBJV).

Figure 12 shows monthly net pipeline flows along the South West Queensland Pipeline, which links the Cooper Basin to Queensland. From December 2015, gas no longer flowed from Queensland south via Moomba in the Cooper Basin. Instead, a large amount of gas, some of which would have previously flowed south, flowed from the Cooper basin to Queensland.

Figure 12: Net pipeline flows on the South West Queensland Pipeline, monthly



Source: AEMO

The third phase: price stabilisation

From around mid-2017, prices moderated across the East Coast gas market. Domestic spot prices declined, as shown in Figure 6. Offers being made to large commercial and industrial users for gas supply in 2018 eased from A$10-15/GJ in early 2017 (US$8-12/MMbtu) to A$8-12/GJ in the second half of the year (US$6-9/MMbtu).[26] Small industrial customers also saw prices for new GSAs decline from A$15-20/GJ in mid-2017 (US$12-16/MMbtu) to A$10-12/GJ in January 2018 (US$8-9/MMbtu).[27]

On average, wholesale gas prices for all consumers in the East Coast gas market appear to have settled around LNG netback levels in the North and, in the southern market, slightly above the cost of gas in the North, partly reflecting transport costs from North to South.[28]

The recent decline in domestic gas prices appears to have been driven, at least in part, by the LNG projects increasing, in aggregate, the amount of gas sold to the domestic market. When gas prices started to decline in quarter three 2017, the net contribution of LNG projects to the domestic market was at its highest level in two years (Figure 9). Increased domestic sales by LNG projects likely helped to support competition in the South. Gas flows from the Cooper Basin to the southern market increased substantially from mid-2017, mainly along the Moomba to Adelaide Pipeline. From mid-2017, gas also flowed from Queensland to the southern market via the Cooper Basin for several months (Figure 12). In addition to increasing domestic gas sales in quarter three 2017, LNG projects agreed to new gas supply arrangements with domestic customers for 2018 and beyond.

The sudden withdrawal and subsequent return of LNG project supply to the domestic market was associated with the commissioning phase of the LNG projects. For these projects, timing the ramp up of CSG production with the start of LNG exports could have been difficult, making domestic gas purchases an attractive option during the commissioning of the LNG projects. Australia's East Coast projects were the first CSG to LNG projects and CSG production brought particular challenges. Unlike conventional gas production, CSG production requires constantly drilling new wells and wells can only be shut-in and production restarted at considerable expense.[29]

There were also uncertainties during the commissioning phase that made LNG projects reluctant to offer gas to the domestic market. LNG operations were still collecting information on their well production, decline rates and productive potential of their undeveloped reserves as LNG projects started up.[30] The testing of LNG facilities during commissioning may have also made supplying gas to the domestic market an unattractive option. For example, APLNG needed a large amount of gas for a two-train 90-day test in mid-2017, where trains were run at 110% of nameplate capacity as part of the project financing terms.[31]

Uncertainties over the future supply-demand outlook during commissioning likely contributed to higher offers from domestic producers. A lack of a clear reference price for selling gas domestically may

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[26] ACCC (December 2017), Gas inquiry 2017-2020: interim report, pp12-13.

[27] Oakley Greenwood (forthcoming), Gas Price Trends Review 2017, pp12-13. See also ACCC (December 2017), Gas inquiry 2017-2020: interim report, p52.

[28] In December 2017, LNG netbacks from oil-linked contract prices were around A$8.40 at Wallumbilla, Queensland. Netbacks from Asian LNG spot prices were around A$10.90 at Wallumbilla. According to the ACCC December 2017 Gas Inquiry, the average wholesale gas price for supply in 2018 agreed between producers and all consumers (including GPG, retailers, and industrials) between the start of 2016 and November 2017 averaged A$8.45/GJ in the North, compared to A$9.01/GJ in the South.

[29] EnergyQuest (2009), Australia's natural gas markets: connecting with the world, https://www.aer.gov.au/system/files/EnergyQuest%20essayâ€"Australia%27s%20natural%20gas%20markets.pdf

[30] ACCC (2016), Inquiry into the East Coast gas market, p27.

[31] APLNG media release (24 August 2017), Australia Pacific LNG satisfies all project finance tests, https://www.aplng.com.au/content/dam/aplng/media-release/2017/APLNG%20project%20final%20finance%20completion%20test%20-%20media%20release%20-%2020170824%20-%20FINAL.pdf

have compounded matters, with suppliers using offers as a form of price discovery in a shifting market.

It seems likely that the potential for export restrictions to be introduced (discussed further in Section 3) accelerated the return of, or even increased, domestic gas sales by the LNG projects and LNG project participants. There were certainly a range of domestic supply agreements announced by both the LNG projects and LNG project participants following a meeting in March 2017 between the Government and exporters and the announcement of the Australian Domestic Gas Security Mechanism (ADGSM) in April. These announcements are detailed in Figure 13.

Figure 13: Gas supply agreements and other commercial arrangements announced since 15 March 2017

Date	LNG project / LNG project participant	Announcement	Buyer	Volume (PJ)	Duration
21 Mar 17	QGC Joint Venture	Drilling of up to 161 wells as part of Project Ruby	n/a	n/a	16 months
29 Mar 17	Origin	Gas supply for Pelican Point power station	Engie	n/a	Jul 2017-Jun 2020
29 Mar 17	Origin	Gas supply for customers in South Australia and Victoria	Engie	8	2018-2019
6 Apr 17	QGC Joint Venture	Gas supply for Pelican Point power station	Engie	8	n/a
6 Apr 17	QGC Joint Venture	Gas supply from Surat Basin for industrial customer	Orica	n/a	18 months
8 May 17	Arrow Energy	FEED phase announced for Tipton gas project	n/a	n/a	n/a
14 Aug 17	GLNG and Santos	Gas supply for Pelican Point power station	Engie	15	Starts Jan 2018
30 Aug 17	Santos	Gas swap facilitating supply to southern market	n/a	18	2018-2021
7 Sep 17	GLNG and Santos	Supply for domestic consumers on the East Coast	n/a	30	2018-2019
8 Sep 17	Santos/Origin	Agreement to continue supply of ethane gas	Qenos	27	2017-2019
26 Oct 17	APLNG	Additional supply for the domestic market	Origin	41	2017-2018
9 Nov 17	Santos	Swap of uncontracted CSG for Cooper basin gas to facilitate supply to southern market	n/a	n/a	n/a
1 Dec 17	Arrow Energy	27-year gas sales agreement	QCLNG	240 per annum	Starts ~2020
20 Dec 17	GLNG and Santos	Gas supply for domestic market	n/a	15	2018

Notes: Shell's QGC Joint Venture operates QCLNG. Shell and PetroChina own Arrow Energy.
Source: company websites.

While prices were on the rise in early 2017, a gas crisis emerged with the Australian Energy Market Operator (AEMO) projecting a gas shortage in coming years. The next section describes these events and policy response of the Australian Government.

Section 3: The East Coast gas crisis

Concerns over electricity supply

Several events over late 2016 and early 2017 raised concerns about the security of electricity supply in Australia's National Electricity Market (NEM).[32] On 28 September 2016, a heavy storm swept through South Australia leading to a state-wide blackout.[33] The storm tripped a protection setting at nine wind farms, causing wind power to fall sharply, and the subsequent overload and shutdown of the interconnector through which South Australia imports electricity from Victoria. Around 850,000 customers lost electricity supply, including households and industry.

In November, the closure of the Hazelwood coal-fired power station (which accounted for around 20% of Victoria's power supply) was announced for March 2017.[34] A second blackout occurred in South Australia during a heatwave on 8 February 2017, which affected 40,000 households. AEMO ordered electricity supply to be restricted for 27 minutes to maintain system security after an offline gas generation unit was not available due to a lack of gas and an insufficiently fast restart time.[35] Two days later, further load shedding was required in New South Wales, with electricity supply to the Tomago aluminium smelter curtailed.

A projected gas shortfall and the Australian Domestic Gas Security Mechanism

In March 2017, AEMO released a report projecting gas shortages in the East Coast gas market starting in 2019 and lasting through to 2024. Growing demand (driven by increased LNG exports), coupled with flat CSG production and a sharp fall in offshore Victorian production, was forecast to leave the domestic market short of gas. AEMO cautioned that either electricity supply shortfalls or industrial closures were possible. In the context of recent events in the NEM and rising gas prices, the report attracted significant attention.

In response to AEMO's report, the Australian Prime Minister called a meeting with Australia's East Coast LNG exporters.[36] Two of the LNG projects, APLNG and QCLNG, committed to being net contributors to the domestic market (i.e. to produce more gas than they exported). The third, GLNG, did not make this commitment.

Following a second meeting with the LNG exporters in April, the Government announced the Australian Domestic Gas Security Mechanism (ADGSM), stating that the requirement for each LNG exporter to be a net contributor to the domestic market had not been met.[37] Under the ADGSM, the Government can restrict the exports of an LNG Project that is not a net contributor of gas to the domestic market when

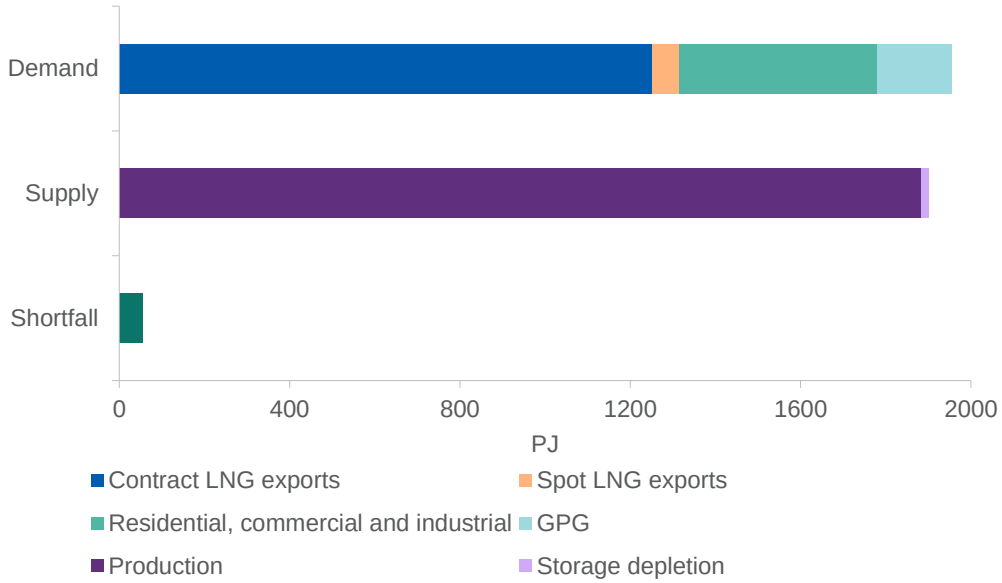
[32] The NEM and the East Coast gas market cover the same states: Queensland, New South Wales, the Australian Capital Territory, South Australia, Victoria and Tasmania. The Northern Territory and Western Australia are not connected to the NEM.
[33] AEMO (March 2017), Integrated Final Report – Black System South Australia 28 September 2016
[34] AEMO (2016), Market insight report – Victoria's supply outlook, https://www.aemo.com.au/-/media/Files/Media_Centre/Insights/AEMO-Market-Insight-Report-Victorias-supply-outlook031116.pdf, Engie (3 November 2016), Hazelwood power station in Australia to close at the end of March 2017, https://www.engie.com/en/journalists/press-releases/hazelwood-power-station-australia/, AEMO (23 March 2017), Media Statement – AEMO reaffirms position on energy security, https://www.aemo.com.au/Media-Centre/AEMO-reaffirms-position-on-energy-security
[35] AEMO (15 February 2017), System Event Report South Australia, 8 February 2017, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/System-Event-Report-South-Australia-8-February-2017.pdf
[36] Prime Minister's Office (15 March 2017), Media release: measures agreed for cheaper more reliable gas, https://www.pm.gov.au/media/measures-agreed-cheaper-more-reliable-gas
[37] Prime Minister's Office (27 April 2017), Media release: delivering affordable gas for all Australians, https://www.pm.gov.au/media/delivering-affordable-gas-all-australians

a gas shortage is projected for the forthcoming calendar year.[38] An LNG project is in net-deficit if the total amount of gas it uses (exports plus gas used in processing) is greater than the sum of: (a) its own gas production and (b) third party gas sourced by the LNG project that has been primarily developed for the purposes of export.

A deal is struck

On 25 September 2017, two reports were released showing projected gas shortfalls in the East Coast market in coming years. The ACCC Gas Inquiry identified a supply shortfall of 55 PJ in 2018, which could reach 108 PJ under a high domestic demand scenario. Importantly, the ACCC identified 63 PJ of gas earmarked for export on LNG spot markets. A report from AEMO showed a similar gas shortfall in 2018, and a shortfall of 48 PJ to 102 PJ in 2019.

Figure 14: Forecast supply and demand in the East Coast gas market in 2018



Source: ACCC, September 2017 Gas Inquiry

On 3 October 2017, an agreement between the Government and Australia's East Coast LNG exporters was reached.[39] LNG exporters committed to offer sufficient gas to the domestic market to meet future gas shortfalls. LNG projects also committed to offering uncontracted gas to the domestic market before selling this gas to international customers. Given these commitments, and the ACCC previously having identified 63 PJ of uncontracted gas that was to be exported in 2018 (sufficient to cover the projected shortfall), restrictions on LNG exports using the ADGSM were not put in place for 2018. A subsequent ACCC report in December found that a gas shortfall in 2018 was no longer expected, with LNG projects having increased their sales to the domestic market and reduced the amount of gas they expected to export.[40]

[38] Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2017, https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Pages/Australian-Domestic-Gas-Security-Mechanism.aspx

[39] Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment, https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Documents/Heads-of-Agreement-The-Australian-East-Coast-Domestic-Gas-Supply.pdf

[40] ACCC (December 2017), Gas inquiry 2017-2020: interim report, pp20-23.

Section 4: Future challenges in the East Coast gas market

There are wide range of future issues to consider in the East Coast gas market.[41] The analysis in this paper points to the risk of LNG projects reducing the amount of gas they supply to domestic consumers or potentially increasing purchases from third party domestic producers to support LNG exports. The domestic market on the East Coast is relatively small compared to East Coast LNG exports: in 2016-17, LNG exports were around double domestic gas consumption.[42] As such, even small swings in how much gas LNG projects produce and how much of this gas they export can have a profound influence on the domestic market.

The gas developed by LNG projects and the proportion of that gas supply which is made available to the domestic gas market will become increasingly important. The LNG projects (APLNG, QCLNG and GLNG) own 61% of Proved and Probable (2P) gas reserves on the East Coast – those with a 50% chance or greater of commercialisation.[43] If reserves controlled by participants in LNG projects are included (e.g. Origin, Santos, Shell) this number rises to 88%.[44] These reserves are almost entirely CSG located in Queensland. Conventional gas reserves on the East Coast are in decline and prospects for major new discoveries remain limited. The picture remains largely unchanged if 2C resources, which are considered less commercially viable than 2P reserves, are included.

There are a number of scenarios under which LNG projects would have incentives to reduce their net contribution to the domestic market. The three East Coast LNG projects have contracts for around 1300 PJ of exports per annum (33 bcm), but the minimum amount buyers can purchase on these contracts is thought to be around 1100 PJ. If buyers purchase their contracted volumes (or above contract), this could soak up the production capacity of the LNG projects' CSG assets, potentially reducing the flexibility the projects have to sell gas to the domestic market.

LNG projects might also reduce the amount of gas they supply to the domestic market or increase third party gas purchases if global LNG prices increase, especially if prices increase for a sustained period of time. The cost overruns experienced in the construction of the LNG projects together with low oil and gas prices have led to poor project economics, evidenced by the company write-downs over the past year.[45] This has put projects under pressure to minimise costs and maximise sales revenues as shareholders seek to recover their investments.[46] In November 2017, Origin reported that it plans to reduce capital and operating expenditure by more than A$500 million (US$380 million) per annum over 18 months at APLNG, and will then target further cost cuts.[47] The acquisition of BG Group by Shell in 2016 will add additional scrutiny to the economics of QCLNG.

The economics of the three LNG export projects could be further challenged by developments in global LNG markets. Global LNG supply is expected to rise from 2017 level of 296 mtpa to close to 400 mtpa by 2021/22 with new production starting up in North America, additional supply from the Middle East, and Australian LNG production stabilising after its rapid build. As this production increases, ahead of

[41] These include rising production costs, AGL's LNG import terminal, the connection of the Northern Territory to the East Coast gas market, moratoria and regulatory restrictions on new gas developments, competition in the southern market, gas pipeline regulation and retail margins.
[42] EnergyQuest (December 2017), EnergyQuarterly data file. Gas use in liquefaction is included in LNG exports for the purposes of this statistic.
[43] EnergyQuest (December 2017), EnergyQuarterly data file.
[44] EnergyQuest (December 2017), EnergyQuarterly data file.
[45] In August 2017, Origin Energy announced that it had wiped A$1.2 bn. (US$ 0.9 bn.) off APLNG's value in one of several impairments In February 2017 the Santos-operated GLNG joint venture wiped A$4.6 bn. (US$3.5 bn.) and the QCLNG project, now owned by Shell, wiped A$4.8 billion (US$3.6 bn.). In August 2017 it was reported that Santos had written down a further A$1.1bn (US$0.8 bn.)
[46] www.gladstoneobserver.com.au/news/energy-giant-ready-to-cut-costs-at-25b-curtis-isla/3213523/ (Gladstone Observer 17th August 2017)
[47] https://www.reuters.com/article/origin-energy-outlook/update-1-australias-origin-energy-targets-aplng-cost-cuts-reaffirms-forecast-idUSL3N1NX5TQ

rises in LNG demand, spot and short-term LNG prices are expected to remain weak, although potentially volatile. This would put further pressure on the LNG projects to maximise returns through selling gas to the highest priced market, be it domestic or export.

LNG project supply to the domestic market could also be affected by the performance of CSG assets. East Coast LNG projects are expected to have a minimum life-span of 20 years and LNG plants often operate for 40+ years.[48] With production at contract levels (94% of nameplate capacity), LNG projects currently have 23 years of 2P reserves. However, some 2P reserves may have a probability of commercialisation as low as 50%. If 2P reserves underperform, then LNG projects will need to rely on 2C resources of unknown commercial viability, even over the course of their minimum life span. If LNG projects begin to face risks around meeting their contracts to international customers, they may be less willing to sell gas to domestic consumers, or even look to source gas from third parties to extend the life of their own reserves.

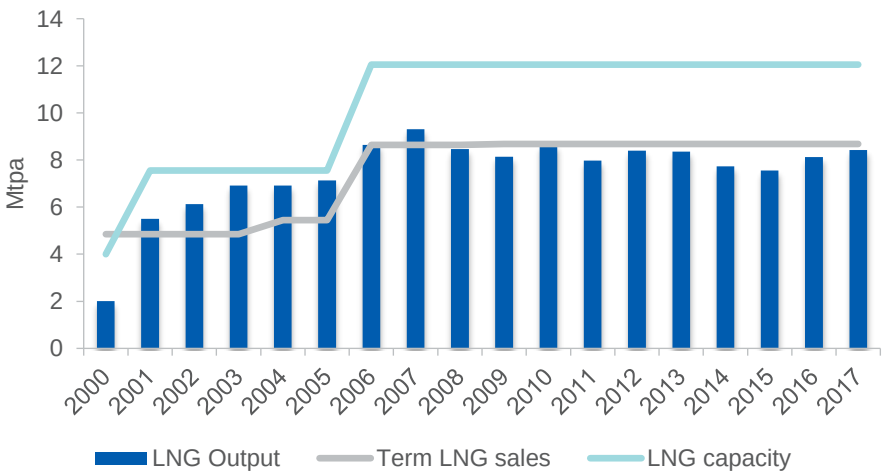
Section 5: Gas crises in Oman and Egypt

Other countries, such as Egypt and Oman, have also experienced domestic gas supply shortages following the start-up of their LNG export projects. In both cases, this led to a fall in LNG exports but, once additional domestic gas became available, LNG exports resumed or increased. Much like the Australian East Coast gas market, Oman and Egypt have large LNG capacity relative to their domestic market (18 bcm capacity vs. domestic market demand of 40-50 bcm). In Oman gas is bought from the government, while in Egypt gas is sold by offshore gas producers to the Egyptian Natural Gas Holding Company (EGAS) for supply to the domestic market.

Oman

The two train Oman LNG started operations in 2000 followed by the one train Qalhat LNG in 2006. Both these projects were project financed using third party banks, which led to the assumption that sufficient gas reserves had been dedicated by the government (who own the gas resource in Oman) to the projects to ensure that LNG could be produced at near capacity.

Figure 15: Oman LNG production, plant capacity and term sales



Source: GIIGNL (production) and Natural gas markets in the Middle East and North Africa, OIES, Ed. Bassam Fattouh and Jonathan P Stern, 2011, Chapter 11"Natural Gas in Oman" David Ledesma

[48] Australian Government Bioregional Assessments, Coal seam gas projects under construction, http://www.bioregionalassessments.gov.au/assessments/12-resource-assessment-maranoa-balonne-condamine-subregion/12321-coal-seam-gas-projects-under-construction https://www.originenergy.com.au/about/who-we-are/what-we-do/exploration-production.html

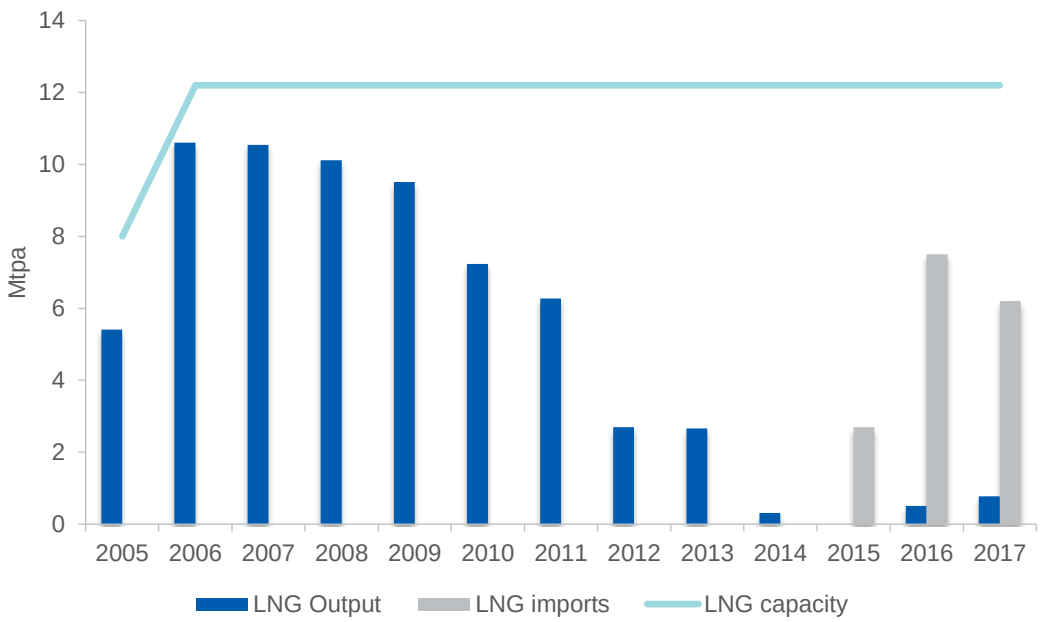
In reality, the need to develop the Omani economy and to increase jobs, led to the development of gas-intensive industries, water de-salination plants, and an increase in power demand and the need for additional gas fired generation. Oman also needed to prioritize gas for enhanced oil recovery. These factors combined to result in gas being diverted away from the LNG export plants to meet local requirements.[49] The shortfall of gas led to the government introducing financial incentives in order to develop more gas reserves and to consider importing gas from Qatar (via the United Arab Emirates) and Iran. The most notable new gas discoveries were the BP operated Khazzan and Makarem fields which started production in 2017. In January 2018, BP announced that it had signed a 1.2 mtpa term LNG purchase agreement with Oman LNG,[50] increasing Oman's term LNG contracts to just under 10 mtpa.

In this way, during a period of gas shortfall, the Omani government (the majority shareholder in the LNG export projects) sought to reduce Oman's LNG output to the minimum required to meet LNG term contractual obligations. When gas supply increased again, the country was able to increase LNG production and utilise more of its LNG liquefaction capacity. It is not clear what will happen when the existing Oman LNG joint-venture agreement comes to an end in 2024. On one hand the government will want to ensure maximum gas is available for the domestic market while on the other, the government earns valuable export revenues from LNG exports. Oman has been in discussions with Iran about importing gas by pipeline with potential that some of the gas could be liquefied and exported from Oman as Iran currently has no liquefaction capacity.

Egypt

The two Egyptian LNG projects, the two train 7.2 mtpa Idku plant and the one train 5.0 mtpa Damietta plant, both started operations in 2005. By 2006 the plants were producing 10.6 mtpa (87% capacity), which was good for a first full year of operations.

Figure 16: Egypt's LNG production, plant capacity and term sales



Source: GIIGNL (production), author

[49] Natural gas markets =in the Middle East and North Africa, OIES, Ed. Bassam Fattouh and Jonathan P Stern, 2011, Chapter 11"Natural Gas in Oman" David Ledesma

[50] Oman LNG and Qalhat LNG are now merged into one entity called Oman LNG.

Egypt's booming domestic demand for gas, together with its gas price subsidy policies that were constraining upstream gas exploration,[51] led to a shortfall in gas supply for the domestic market. This led to a prioritisation for locally produced gas to the domestic market and a closure of the Damietta LNG plant in 2013 and the near-closure of the Idku plant in 2014. To address its gas shortage, Egypt constructed two LNG import projects using floating storage & regasification units (FSRU) and in 2016 imported 7.5 mt LNG, quite a turnaround from exporting a similar amount in 2010.

In 2015 ENI discovered the giant offshore Zohr gas field, with an estimated 30 tcf gas reserves with expected production of 1.2bn ft^3/day, the equivalent to about one-fifth of current Egyptian production.[52] In December 2017, first gas was produced from the field. In early 2017, BP announced that gas was starting to flow from its 1.2bn ft^3/day West Nile Delta field. With the discovery of these gas reserves and production start-up, LNG exports increased slightly to 0.5 mt in 2016 and 0.8 mt in 2017 from the Idku plant. It is expected that output will increase further in 2018. At the same time, Egypt scrapped its plans to build a third FSRU LNG import terminal[53] and announced that it was planning to close one of the two existing terminals.

Key messages

The approach taken by Egypt, as with Oman, shows when gas is required domestically it is politically difficult to justify LNG exports. Egypt, unlike Oman, went one stage further and in 2012 and cut gas supply to the LNG plants so that not even term contract commitments could be supplied. In countries that have limited or remote gas reserves, the reserves required for an LNG project are normally dedicated to the project and additional gas reserves are not developed unless there is a specific domestic need. If there are delays in developing new gas reserves, prices spike, or domestic gas demand is not fulfilled, signalling the need for additional gas supply. This is what happened in Egypt and Oman.

In Australia, the supply response was likely hampered by low oil prices and moratoria and regulatory restrictions. In New South Wales, for example, the state government introduced strict regulatory restrictions on CSG developments in late 2013. In Victoria, the state-government halted approvals for hydraulic fracturing in August 2012, eventually banning onshore unconventional gas development in March 2017, and introduced a moratorium on onshore conventional gas development in 2014 that will remain in place until mid-2020.[54]

Egypt and Oman responded to gas shortfalls through encouraging domestic gas exploration using fiscal and gas price incentives, which in both cases have resulted in additional gas reserves being found which will lead to a rise in LNG exports from both countries. In Egypt's case, gas shortfalls also led to LNG being imported. This is an option that is being considered in Australia. AGL, an Australian energy retailer, is considering investing A$250 million in an LNG import terminal that would start operations in 2020 or 2021.

In sum, LNG project developers in countries with markets that have historically been small, stable, and isolated, face the risk that gas may be diverted away from newly developed LNG export projects unless new gas is developed to be used domestically at the time that gas production is developed for LNG

[51] Natural gas markets in the Middle East and North Africa, OIES, Ed. Bassam Fattouh and Jonathan P Stern, 2011, Chapter 4"Egypt's natural gas market: So far so good, but where to next?", Hakim Darbouche and Robert Mabro
[52] http://www.petroleum-economist.com/articles/midstream-downstream/lng/2017/egypt-gas-to-the-rescue (Petroleum Economist 18/7/17)
[53] Petroleum Economist 18/7/17
[54] Media release for the Hon Michael O'Brien MP (August 2012), Reforms to strengthen Victoria's coal seam gas regulation and protect communities, https://www.asx.com.au/asxpdf/20120828/pdf/4289jfjdxcjk1k.pdf; Carter Newell Lawyers (June 2014), Victoria widens moratorium to include all onshore gas development, http://www.carternewell.com/page/Publications/Archive/Victoria_widens_moratorium_to_include_all_onshore_gas_development/

exports. The case of Australia also suggests that the commissioning phase of LNG projects can present particular challenges for the domestic market.

Conclusion

In its September 2014 paper, the OIES identified that the lack of available gas resources (especially at the Santos-sponsored GLNG), together with the uncertainty over the deliverability of supply in the initial stages of CSG development at QCLNG, would lead to projects contracting for significant amounts of third party supply with a resultant rise in domestic gas prices. The paper also identified that gas prices would rise towards export netback levels, unless governments approved gas exploration and production within their states to increase domestic gas supply.

The paper did not foresee, however, that prices in the East Coast gas market would rise above LNG netback levels between mid-2016 and mid-2017. Early gas associated with the development of LNG export projects had been directed to the domestic gas market and this supply increased in the lead up to LNG exports. From around mid-2016 to mid-2017, during the commissioning phase of the LNG projects, LNG exporters reduced the amount of gas they were supplying to domestic customers and domestic gas prices escalated rapidly. Following policy intervention and the end of the commissioning phase, LNG project supply to the domestic market increased again and East Coast gas prices fell and now appear to have settled around LNG netback levels.

This analysis of Australia's East Coast gas crisis points to the longer-term challenges of maintaining LNG project supply to the domestic market as the market becomes increasingly dependent on Queensland CSG. There are a number of factors – including strong global LNG demand, a sustained period of high LNG prices, or the underperformance of CSG resources – that would create incentives for LNG projects to reduce their gas sales to domestic consumers and potentially increase purchases from third party domestic producers.

Australia's East Coast gas crisis is not unique. The experiences of other countries developing a domestic LNG industry – notably Oman and Egypt – have been similar. Much like Australia, these countries had small domestic markets relative to the scale of LNG exports. This points to the greater need for planning to meet future domestic gas needs. At the same time, the balance of revenues earned from gas exports vs. the value of this gas to the domestic market and broader economy needs to be considered.

Conversions

1 mt = 54.4 PJ

1 mt = 1.361 bcm

1 bcm = 39.971 PJ

1 MMbtu = 1.055 GJ

For the purposes of converting AUD to USD, an exchange rate of A$1 = US$0.75 was used throughout the paper.

Glossary

2C	Contingent reserves
2P	Proven and probable reserves
ADGSM	Australian Domestic Gas Security Mechanism
A$	Australian dollars
APLNG	Australia Pacific LNG
AEMO	Australian Energy Market Operator
ACCC	Australian Competition and Consumer Commission
Bcm	Billion cubic metres
Bn.	Billion
CSG	Coal Seam Gas (also known as coal bed methane)
DWGM	Declared Wholesale Gas Market
EGAS	Egyptian Natural Gas Holding Company
FID	Final investment decision
FSRU	Floating storage and regasification unit (LNG vessel)
FSU	Floating storage unit (LNG vessel)
ft^3/day	Cubic feet per day
GBJV	Gippsland Basin Joint Venture
GLNG	Gladstone LNG
GJ	Gigajoule
GPG	Gas power generation or gas power generator
GSA	Gas supply agreement
JCC	Japan Customs-cleared Crude
LNG	Liquefied natural gas
MMBtu	Million of British thermal units

Mt	Million tonnes
NEM	National Electricity Market
OIES	Oxford Institute for Energy Studies
pa	per annum
PJ	Petajoule
QCLNG	Queensland Curtis LNG
STTM	Short term trading market
Tcf	Trillion cubic feet
TWh	Terawatt-hours
US$	US dollars