SUBMISSION

ACCC REVIEW OF LNG NETBACK PRICE SERIES | 12 APR 2021

INTRODUCTION AND SUMMARY

The Energy Users' Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

We welcome the opportunity to provide a submission on the calculation of the LNG netback price series. The publication of the series has provided much needed transparency around what the ACCC describes as 'an indicative reference price'[1]. The ACCC sees it as a 'relevant price marker in negotiations for domestic supply' subject to some qualifications and regularly reports on how offer prices differ from it as evidence of the lack of a competitive market.

This submission provides comments on the range of questions asked by the ACCC in its Issues Paper with particular focus on those around length of the forward netback series, LNG price and LNG plant costs. In particular we propose three key changes:

1. Tenor - Extending the forward price series beyond the current two year maximum to at least 5 years and out to 10 years if possible
2. Marker - Developing LNG netback prices series based on both JKM (to reflect what is happening now) and Henry Hub (to reflect what we expect to happen in the near future)
3. Costs - That costs associated with Gladstone LNG plant capex and fixed opex as well as pipeline capex also be deducted in the LNG netback calculation

Our approach is informed by our view that the ACCC's netback calculation is looking from the perspective of the seller, not the buyer. Given the objective of the series to help move the market down the path to competitiveness and reduce the information asymmetry C&I buyers face, we think the ACCC should be looking from the buyer's perspective. So rather that asking:

> 'what costs will the seller not incur to sell excess gas domestically rather than to the LNG market?' (the sellers' perspective)

the question should be:

[1] ACCC "Guide to LNG netback price series" October 2018 p. 6 https://www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20October%202018_0.pdf

'what costs are incurred by the LNG producer to supply that excess gas to a domestic customer?' (the buyers' perspective)

This approach puts the LNG producer and the local producer on a level playing field. It concentrates the focus on what a well-functioning competitive market should provide, rather than the current situation where, as ACCC gas reports show, gas sellers exercise market power. It recognises that there are a variety of gas suppliers, not just vertically integrated LNG producers that have invested a lot of capital to meet their long term LNG commitments. It asks gas buyers to pay for the services that they are actually receiving.

We understand that even were the outcomes we propose to the LNG netback calculation implemented, gas sellers will still have the ability to extract rents above normal profits from C&I consumers. Years of ACCC reports shedding light on sellers' pricing practices and years of publishing LNG netback prices, have had little impact on reducing sellers' ability to extract these rents. While COVID impacts on world LNG demand/supply balance saw offer prices fall in 2020, we think this is temporary.

This continues no matter the level of jawboning and naming and shaming by the ACCC and its Chairman. We argue that the proposals in this submission will go some way to addressing that concern and should be seen in the wider context of a whole array of measures in the Prime Ministers Gas Fired Recovery Policy Statement of September 2020.

We also think the proposals in this submission are key to the more effective implementation of the recently negotiated Heads of Agreement with the LNG exporters and will form an integral part of the Code of Conduct currently being negotiated by the EUAA and other user organisations with the APPEA.

What is the role of the LNG netback price?

The ACCC's Gas Inquiry's first interim report in September 2017 highlighted the widespread concerns that East Coast C&I consumers had about the level and volatility of prices they were being charged. C&I consumers were particularly concerned about the lack of transparent pricing information available to help them in a negotiation where they suffered significant information asymmetry given the confidential nature of gas contract terms. Gas producers used confidentiality clauses to ensure these details were never made available to assist other consumers in their negotiations. As the ACCC noted[2]:

> "A key problem for C&I gas users was the lack of an indicative price for gas in the East Coast Gas Market. The gas market was opaque and dominated by confidential bilateral contracts, giving C&I gas users limited insight into the prices being agreed in the market. The short term trading markets and gas supply hubs in the East Coast Gas Market remained relatively thinly traded, so prices were not representative. There was limited shared understanding of what the most relevant LNG netback price marker was or how it should be calculated."

So the ACCC saw the role of the LNG netback price as filling this gap[3].

[2] ACCC "Guide to LNG Netback price series" October 2018 p. 5
https://www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20October%202018_0.pdf
[3] Ibid

> "Under current market dynamics, LNG netback prices based on Asian LNG spot prices play an important role in influencing domestic gas prices in the East Coast Gas Market."

The evidence in the ACCC's January 2021 Interim Report provides clear evidence that this objective has not been achieved[4].

> "Specifically, internal documents suggest some Queensland suppliers view LNG netback prices as a price floor, with the threat of regulatory intervention acting as more of a constraint on suppliers keeping prices below $10 per gigajoule. And in southern states, suppliers have tended to focus on the buyer alternative (LNG netback price plus transport), with some appearing to target even higher prices."

Sellers extract rents simply because they have the market power to do so.

The way the ACCC presents the data is what *does* happen – prices are driven by LNG producers selling uncontracted gas, calculate the LNG netback based on a short run opportunity cost for an LNG producer that then applies to Queensland offers and then add on transport costs to get the southern states 'buyer alternative'.

Our proposition is that the ACCC approach to providing price transparency data should be based on what *should* happen to promote a properly functioning competitive market – for example the removal of capex and fixed opex from the netback series to show the marginal cost of molecules in the gas rich fields of the Surat basin and Queensland more broadly. This is what is required to achieve the ACCC's 2018 objective and better redress the current information asymmetry faced by C&I customers in their GSA negotiations.

Specific Comments on the Questions Asked

1. The length of the forward LNG netback price series

We welcome the ACCC extending out the term of the forward prices as data becomes available. Yet this is only two years. We would like to see the price series do 1/2/3/4/5 and even longer terms out to 10 years if possible.
We understand there is an argument something like 'why provide longer term forward prices when contracts are generally two years or less?' We think this approach has the story upside down.

Prior to the advent of the LNG projects, our members regularly did contracts of 5-10 years. These helped underpin the long-term capital decisions our members needed to make. It is no different from the LNG producers requiring long term sales and purchase agreements to underpin their LNG plant investment. Yet they expect buyers to survive on short term contracts.

The exercise of market power by suppliers dictates the contract terms offered to our members. We doubt it is in the interest of gas suppliers to offer terms longer than two years because they wish to retain the International Continental Exchange data given it is based on JKM data. We understand that there is JKM data out to ~5 years but the longer the term the less liquid the data. It would be helpful if the ACCC's draft position paper in late June provided data on the JKM liquidity for terms longer than 2 years and the decision rule the ACCC uses to decide what is a sufficient market depth to extend the term of the forward prices.

[4] ACCC January 2021 p. 15

A properly functioning competitive market would have enough liquidity to price a range of term contracts beyond the current two years. We understand that while the provision of these expanded LNG netback prices may not lead to increased offers of contracts longer than two years given suppliers market power, at least it will provide the basis for a more transparent discussion. In particular to provide some additional scrutiny for the ACCC to assess LNG producer compliance with the 2021 Heads of Agreement. How can an obligation to offer gas '…on competitive market terms' allow the LNG producer to dictate the term offered?

2. LNG price

There has been a lot of debate around the relevance of a Henry Hub price index to the Australian market. The supply side claims that it is not relevant because, for example, it is a much deeper and more liquid market, it involves a large interconnected pipeline system and there is higher incidence of liquids meaning gas prices are lower than they otherwise would be with dry gas.

We would suggest that all these reasons are irrelevant for both the question the ACCC is answering and the question we think the ACCC should be answering, in calculating the LNG netback. It is simply a reflection of geology that Australian CSM producers do not have liquids and that is something they were well aware of when they made their investment decisions. It should not be that Australian domestic customers compensate Australian producers for it. It is an issue for producers to manage in their production costs recognising they only have a gas revenue stream to rely on, not a gas and liquids revenue streams. It is irrelevant that the pipeline system in Australia is different to the US.

What is relevant is:

- The forecast expansion in world LNG gas trade is dominated by Asia
- Given we are looking at the price for marginal LNG cargoes into the Asian market, what is/will be setting the price of these marginal cargoes?
- The US is the marginal supplier into this expanding Asian market and its share of the market has expanded significantly over the last few years and is forecast to continue expanding in the next 20 years – if not already the US will soon become the marginal supplier of spot gas to Asia
- The price of US LNG exports on the ship in the US is based on Henry Hub
- The Henry Hub market is significantly deeper, longer term and more liquid than JKM

So, as we look to both the current situation as well as the future we see benefits in the ACCC publishing netback data based on both JKM and Henry Hub. JKM is the more important price setter currently but has a limited forward market. Henry Hub is fast becoming the benchmark for spot sales as the US becomes the marginal supplier. It is a much more liquid market than JKM and provides much longer term forward price data.

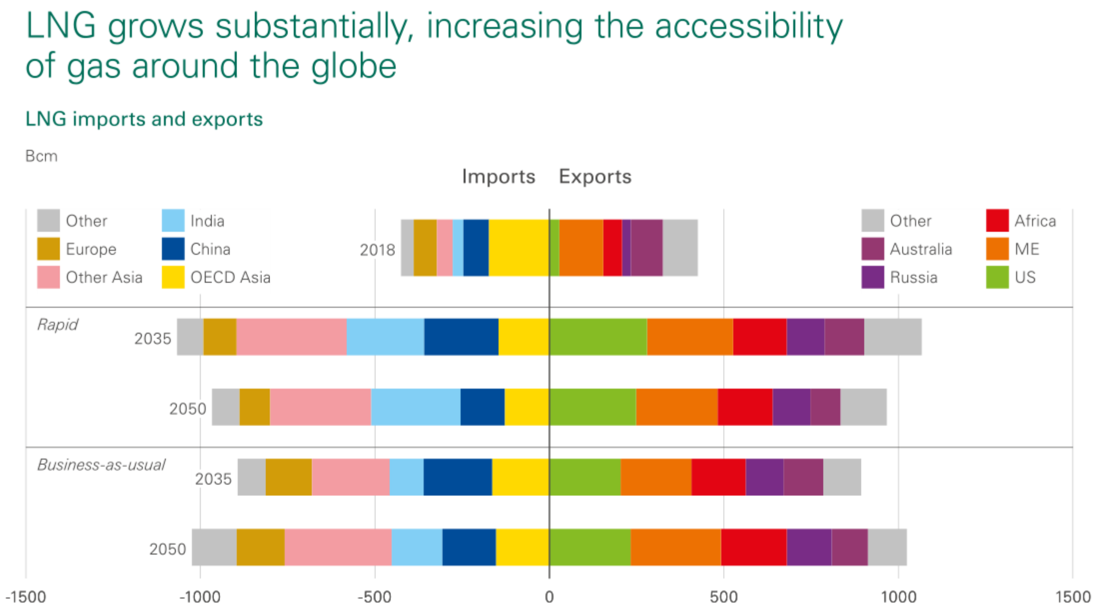
This section argues the case for inclusion of Henry Hub.

The forecast expansion in world LNG gas trade is dominated by Asia

Any number of major forecasts show this. Here is the BP view from its 2020 World Energy Outlook[5] showing two scenarios – Rapid[6] and Business as Usual[7].

LNG expands significantly in both Rapid and BAU, leading to a more competitive, globally integrated gas market. In Rapid LNG trade more than doubles over the first half of the Outlook, increasing from 425 Bcm in 2018 to around 1100 Bcm by the mid-2030s. This fast growth is driven by increasing gas demand in developing Asia (China, India and Other Asia) as gas is used to aid the switch away from coal and LNG imports are the main source of incremental supply. This surge in LNG demand is met by increasing supplies from the US, Africa and the Middle East, which emerge as the three main hubs for LNG exports.

LNG trade in BAU grows more slowly than in Rapid, reaching a little over 1000 Bcm by 2050. However, even in BAU, around 60% of that growth occurs over the next 10 years or so. As in Rapid, US, Africa and the Middle East are the main source of incremental supply, with developing Asia the dominant destination for these increasing exports.



Expansion in US LNG exports

While historically LNG trade in the Asia Pacific region was built on long term sale and purchase agreements to underpin development of new fields, spot and short-term LNG trade has grown dramatically over the past 20 years.

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[5] BP "World Energy Outlook 2020" p. 83 https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2020.pdf?utm_source=newsletter&utm_medium=email&utm_campaign=newsletter_axiosgenerate&stream=top

[6] Policy measures including a significant increase in carbon prices supported by more-targeted sector specific measures, which cause carbon emissions from energy use to fall by around 70% by 2050. This fall in emissions is in line with scenarios which are consistent with limiting the rise in global temperatures by 2100 to well below 2-degrees Celsius above pre-industrial levels.

[7] Assumes that government policies, technologies and social preferences continue to evolve in a manner and speed seen over the recent past. Carbon emissions peak in the mid-2020s but little headway is made in terms of reducing carbon emissions from energy use, with emissions in 2050 less than 10% below 2018 levels.

In 2000, spot and short-term LNG trade amounted to only about 5 MT, just 5% of global LNG trade. By 2019, spot and short-term LNG trade had increased to 119 MT and accounted for 34% of total LNG trade. Most of that growth was in Asia[8].

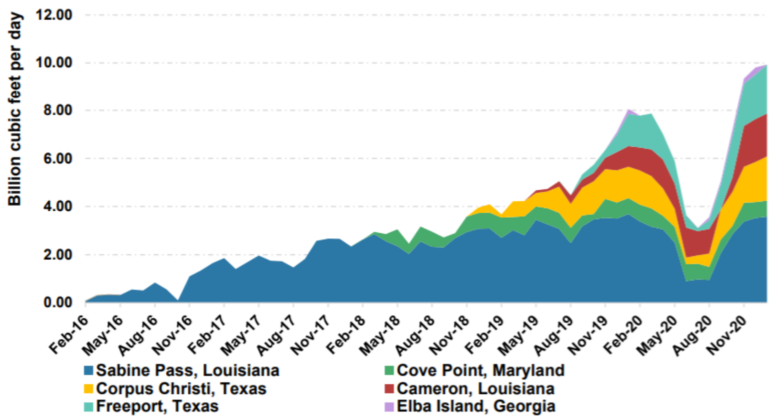
As the Issues Paper notes, the US has recently become a major exporter. US LNG exports are dominated by cargoes going to Asia – 35% of all LNG exports over the 5-year period to January 2021 went to South Korea, Japan and China[9], all priced off a Henry Hub index.

1b. Shipments of Domestically-Produced LNG Delivered – by Country
(Cumulative from February 2016 through January 2021)

Country of Destination	Region	Number of Cargos	Volume (Bcf of Natural Gas)	Percentage of Total U.S LNG Exports (%)
1. South Korea*	East Asia and Pacific	297	1,034.8	16.0%
2. Japan*	East Asia and Pacific	214	742.8	11.5%
3. Mexico*	Latin America and the Caribbean	156	527.8	8.1%
4. China	East Asia and Pacific	138	474.8	7.3%

With the vast majority of that trade occurring in the last 12 months[10]:

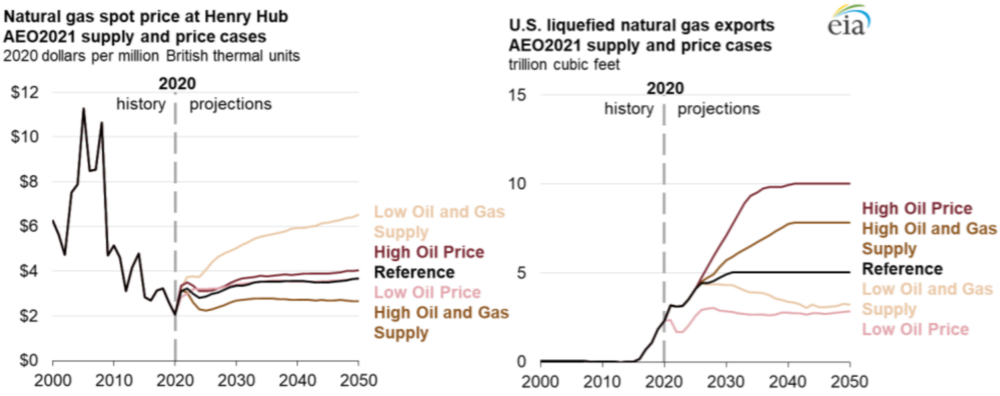
1c. Domestically-Produced LNG Exported by Terminal
(February 2016 through January 2021)



In January 2021, 58% of US LNG exports of 275Bcf went to South Korea, Japan and China[11].

The recently released US EIA forecasts of US LNG exports has them doubling by 2029 in the Reference Case[12].

[8] S. Finizio, J.A. Trenor, and J. Tan "Trends in LNG Supply Contracts and Pricing Disputes in the Asia Pacific Region" Oil, Gas and energy Law Intelligence Vol 18(3) May 2020
[9] Us Department of Energy "LNG Monthly" March 2021 p. 2
https://www.energy.gov/sites/default/files/2021/03/f83/LNG%20Monthly%202021_0.pdf
[10] Op cit p. 3
[11] Op cit p. 1
[12] US EIA "Annual Energy Outlook 2021" March 2021 p.23 https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2021* (AEO2021) Reference, High Oil and Gas Supply, Low Oil and Gas Supply, High Oil Price, and Low Oil Price cases

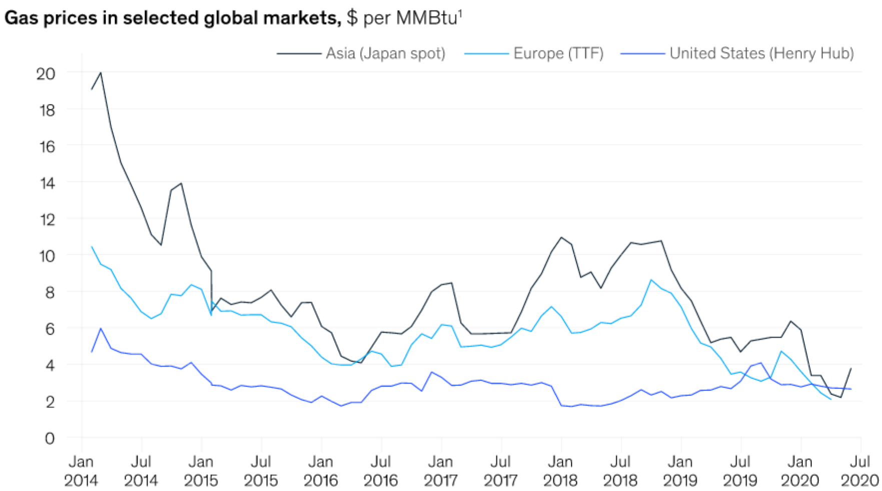
The IEA in its forecast of gas outlook for 2020-25 in June 2020 concluded[13]:

> "On the supply side North America is almost the sole source of growth, accounting for close to 80% of additional exports between 2019 and 2025. North American exports are expected to almost triple in the next five years, driven by the wave of recently sanctioned US liquefaction projects, as well as the commissioning of Canada's first export project by the end of the forecast period."

Leading to an expansion in the role of Henry Hub pricing and a narrowing of price differentials

The expansion of US LNG exports means an expanded role for Henry Hub pricing in world gas markets and the expansion of Henry Hub trading in Asian time zones[14]. Henry Hub is moving to a position of driving Asian LNG spot prices. This expansion of US LNG exports with Henry Hub pricing is driving the convergence of international gas prices [15].

International gas prices have converged.



[1]Million British thermal units.
Source: Bloomberg; EIA; ICE Endex; Platts; McKinsey analysis

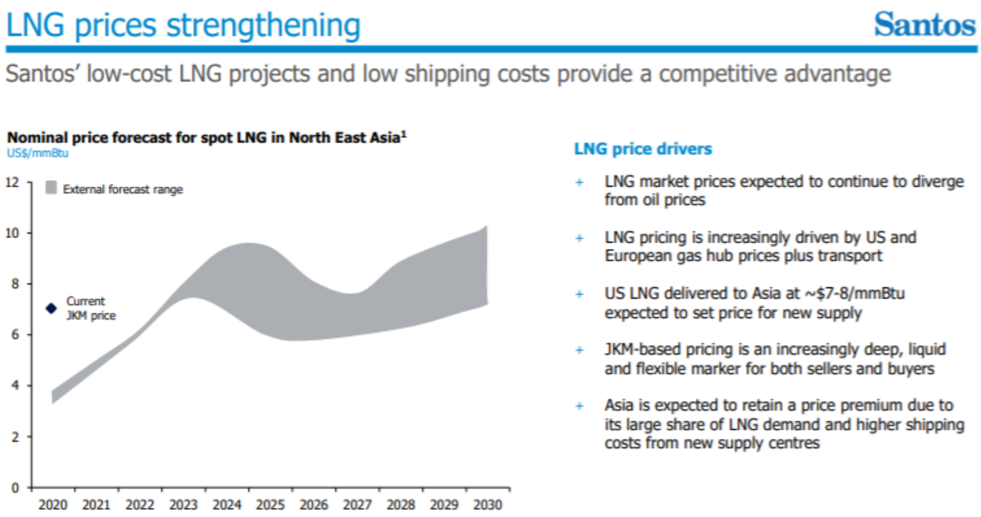
[13] IEA "Gas 2020" p.51 https://www.iea.org/reports/gas-2020/2021-2025-rebound-and-beyond

[14] E.g. Adila Mchich "The Rise of Henry Hub Liquidity" 7 December 2020 https://www.cmegroup.com/education/articles-and-reports/the-global-rise-of-henry-hub-liquidity.html and "Will the US become the home of LNG Price Formation 17 July 2019 https://www.cmegroup.com/education/articles-and-reports/will-the-us-be-the-home-of-lng-price-formation.html

[15] McKinsey & Company "The future of liquified natural gas: Opportunities for growth" September 2020 https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-of-liquefied-natural-gas-opportunities-for-growth#

Santos agrees with the increased influence of Henry Hub[16]:

"LNG pricing is increasingly driven by US and European gas hub prices plus transport"



BHP also agrees[17]:

"North American exports are expected to provide the marginal supply across multiple longer-term scenarios for the LNG industry, with new supply likely to be required to balance the market in the middle of this decade, or slightly later. Within global gas, LNG is expected to gain share."

In its 2020 World Energy Outlook covering the period to 2040, the IEA concluded[18]:

"The US Henry Hub remains an important reference price for global gas markets, and stays in a $2-4 per million British thermal units (MBtu) range through to 2040. Asia is the key growth market for imports, which are increasingly priced off indices that reflect the region's supply-demand balance, rather than oil prices…"

Henry Hub is a much deeper market than JKM

The market advice we have received indicates that while JKM data is available out ~ 5 years, Henry Hub goes out at least 10 years. While the depth of both markets fall over time, Henry Hub has around 100 times greater liquidity than JKM out on the curve. JKM is also more volatile than Henry Hub.

The adjustments to Henry Hub to ensure there is an appropriate comparison with JKM netback

The price a US LNG exporter receives is based on a formula:

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[16] Santos Investor briefing December 2020 slide 21 https://www.santos.com/wp-content/uploads/2020/12/2020-Investor-Day-FINAL.pdf
[17] BHP News Release "BHP Results for the Year Ending 30 June 2020" 18 August 2020 p. 12 https://www.bhp.com/-/media/documents/media/reports-and-presentations/2020/200818_bhpresultsfortheyearended30june2020.pdf?la=en
[18] IEA WEO 2020 p.81 https://www.iea.org/reports/world-energy-outlook-2020

Henry Hub *1.15 +$US2-3/MMBTU.

Consistent with our arguments in 5. below, a Henry Hub LNG netback would exclude the 15% uptake factor and the $US2-3/MMBTU as they reflect the capital costs associated with LNG export. They are costs that are not incurred by US domestic consumers who pay a Henry Hub based price adjusted for transport costs to their particular location.

3. LNG freight costs

We are not experts in this area. However, our discussions with those who are, suggests that the Baltic Exchange is a much better measure of freight costs than Argus. We are told that the Baltic exchange data is based on discussions with a panel of brokers that are arranging charters and that a three year forward price is now available.

These discussions also indicated thinness of the freight forward market beyond around 3 years. This should not be used as an excuse for not publishing netback estimates longer than 3 years. Approaches to address this should be discussed with stakeholders.

4. Conversion to $AUD/GJ

We have two comments on the questions asked here:

- There would be value in publishing the forward prices based on the relevant forward exchange rate applying to the forward pricing period
- We support the continued publication of the excel worksheets used by the ACCC. This enables our members to do their own calculations on forward prices given internal exchange rate forecasts.

5. LNG plant costs

The ACCC's argument that only avoidable costs should be deducted is based on the logic that[19]:

> "…since costs that cannot be avoided in the short-run would not be expected to be taken into account when making short-run commercial decisions"

We believe there are a number of reasons why the LNG fixed plant costs – both capex and opex - should be deducted in the netback calculation for a price marker for uncontracted excess that is above the producers' long-term commitments. The LNG netback calculation should reflect the objective of a competitive market (where those costs would be borne by the equity owners until prices recovered), not the reality of the exercise of market power.

(i) *Selling to domestic customers should not be more profitable than selling to LNG customers*
(ii) *LNG producers do not incur these costs to supply the domestic market so why should domestic customers fund capital to supply LNG customers?*

[19] LNG netback paper p.15

As we argued above, the relevant question is what costs are incurred by an LNG producer to supply a domestic customer? So, it is not a matter of what can be avoided, it is a matter of what is actually incurred.

The decision rule applied by the ACCC assumes that an LNG producer can only make the decision after the gas has been processed through the LNG plant and hence 'incurred' LNG plant costs. The argument seems to be once the gas has been processed, what options does the producer have? We would suggest that this misrepresents the options facing the LNG producer. When 'uncontracted' gas is produced at their fields, they have, in theory, two choices:

(a) Sell it to a domestic buyer, or
(b) Process it at Gladstone and sell it as spot LNG

Under the recently negotiated the Heads of Agreement the LNG producers are unable to sell that uncontracted gas as a spot LNG cargo:

> "…unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market"

So, the gas being offered to domestic customers is never processed through the LNG plant. Why should producers be able to recover costs they have never incurred, to make profits they do not make on their LNG commitments?

(iii) LNG capex is recovered from long term LNG customers, not domestic customers

The original project approvals were based on long term take or pay commitments from LNG off-takers. These commitments were designed to cover recovery of all capex construction (and sustaining) costs and fixed opex costs. So, any sales above those Take or Pay commitments are not required to recover those costs. The only reason for LNG producers being able to do so is simply because their market position allows them to do it.

Now the fact that long-term prices have not turned out to be what was forecast at the time of project sanction - which has led to significant write downs in asset values in recent years[20] - is not an argument to seek to recover this capex from domestic consumers. The fact that some plants have for some periods since commissioning operated at a capacity factor below the Take or Pay level is also not a reason to seek to recover the capex from domestic customers. On some occasions the plants operate at or above their nameplate capacity given strong LNG demand e.g. the 4th qtr. 2020 for ACLNG and APLNG[21]. This is all part and parcel of the project risk that equity owners take on at the time of project sanction. But LNG producers can shift plant capital and fixed OPEX costs to domestic consumers simply because their market position allows them to do so.

6. <u>Pipeline costs</u>

For the same reason that LNG plant capex should be deducted, we think pipeline capex should be deducted. The LNG netback calculation is designed to be the cost at Wallumbilla, not the cost at Gladstone. The purchaser at Wallumbilla is not incurring any costs to get the gas from Wallumbilla to Gladstone so why effectively include that

[20] See e.g. https://www.argusmedia.com/news/2124900-australias-santos-books-700mn800mn-impairment
[21] Energy Quest Energy Quarterly March 2021

cost by only deducting $0.04/GJ for pipeline transport? The full forward haul cost of the Queensland Gas Pipeline (somewhere between $0.70-$1.32/GJ[22])

We look forward to the opportunity to engage further as the inquiry proceeds.

Kind regards,

Andrew Richards
Chief Executive Officer

[22] ACCC January 2021 Interim Report p. 78 https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202021%20interim%20report_3.pdf