ACCC – LNG Netback Price Series Review

Preliminary Report

24 June 2021

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1. Executive Summary

Wood Mackenzie has been tasked with providing information and advice on issues which will inform the Australian Competition and Consumer Commission (ACCC) review of its LNG Netback Series methodology. This preliminary paper:

- Initiates an independent review of the current methodology and its components
- Considers any potential impacts of new domestic and international market conditions on this methodological approach
- Looks to identify questions of market participant alignment over the objective, utility and purpose of the LNG Netback Series
- Investigates if and how alternative datasets might enhance transparency, particularly with regard to extending the timeframe of forecasts
- Will be published in draft format and invite comments and clarifications from market participants

It does not seek to introduce alternative price discovery mechanisms outside of the netback methodology, address asymmetry in domestic gas contracting negotiations, nor comment extensively on other elements which influence price formation in the East Coast Gas Market (ECGM).

Objective of the LNG Netback Series

The ACCC introduced the LNG Netback Series to improve transparency over ECGM gas price formation with its sole purpose being to provide insight into one of the key pricing influences in the market.

The objective of the netback is to assess the price at which an Australian gas producer is indifferent to supplying the domestic or export market. The published price series (based upon the netback calculation) provides price transparency over the alternative (export) market option for a gas producer in the ECGM. As long as there is unmet demand in the ECGM (demonstrated by spare capacity at the Queensland LNG projects) a producer's decision-making over gas sales will necessarily require reference to this option to export.

Methodology

The LNG netback is a concept price and is not a benchmark or marker for domestic gas contracting or pricing. Netback calculations do not have a standardised methodology and approaches differ, depending on the objective and the circumstances of then benchmark metric.

The ACCC LNG netback price is a measure of an export parity price that a gas supplier might expect to receive for exporting its gas. It is calculated by selecting a Reference Price Marker as a proxy for the price that could be received for LNG sales, and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port.

The starting Reference Price Marker has the most material influence overall in the netback calculation. The methodology around production costs, freight costs and conversion factors (e.g. forex), while important subtractions in the calculation, have far less proportional impact on the final unit costs (per mmbtu). Identifying the correct starting Reference Price Marker should consider where the marginal gas molecule will be sold.

Reference Price Marker(s)

Australia's ECGM is linked to the fastest growing gas and LNG demand region globally - Asia - which will require increasing volumes of LNG through to 2030. This provides Queensland LNG exporters with ongoing opportunities for marginal LNG volume sales beyond their contractual commitments, if gas supply is available for export during this period.

Furthermore,

- Queensland LNG spot sales into Asia are the marginal export transactions in the ECGM
- JKM price assessment is set by the marginal spot cargo transacted into Asia (*and future expectations thereof*)

On this basis, the Asian LNG spot price marker, JKM, remains a relevant Reference Price Marker in the ECGM especially for short-term (<2 year) gas sales. For longer-term (>2 year) gas sales, identifying a 'market rate' oil-indexed formula published alongside Brent futures data might be considered as an alternative Reference Price Marker.

This could help provide greater transparency of what the export alternative might look like for a like-for-like gas sale, given that the duration of domestic gas contract is typically >2 years. The JKM forward curve is not deeply traded enough beyond 12 months to provide confidence over its accuracy in the longer term, nor it is it yet a standard price marker for contracts of longer duration in either the LNG or domestic markets.

Treatment of Cost Components in the Netback Calculation

The netback calculation starts with the Reference Price Marker and subtracts the costs of bringing the product to the relevant market. Under the opportunity cost principle, only avoidable costs associated with the production of additional gas molecules should be considered in this calculation.

The capital costs incurred in the development of the Queensland LNG projects are not relevant to short-term decision-making of incremental LNG/gas sales, as these costs are already sunk. Spare LNG capacity at Gladstone provides the opportunity for the Queensland LNG producers to produce and sell incremental LNG. Including a portion of capital and/or fixed operating costs in the netback calculation would distort the methodology such that ECGM producers would no longer be indifferent to supplying gas for export or the domestic market.

JKM Price Formation

JKM is a price assessment set by the marginal transaction into North Asia and therefore is driven by Asia Pacific supply and demand fundamentals, though set by the marginal supply option. In general terms marginal LNG demand will generally be met by the lowest cost supply option which can generate a profit at the price signal on offer. Additional demand will progressively be met by more expensive options, as required to balance the market.

While JKM is mainly driven by LNG supply-demand in Asia, it is increasingly anchored to European pricing dynamics. Low heating demand in the North Asian summer tends to result in Asian LNG prices trading close to European spot prices, which acts as a price "floor" as Europe is the market of last resort for LNG sales.

Higher LNG demand in North Asian winters results in Atlantic basin LNG being required in North Asia. This often sees Asian LNG prices trading at a premium to European (Title Transfer Facility – TTF) prices to cover the cost of shipping differentials, with US LNG shipping differentials to Europe increasingly setting the price in Asia during periods where inter-basin trades occur.

Our analysis highlights that the key international price markers (Henry Hub and TTF) have grown in influence with respect to North Asian prices in recent years, but this is reflective of a global gas market that has become more connected as a whole rather than justification for the LNG Netback Series Reference Price Marker being pegged to either. US and European price markers will have influence and correlate with Asian LNG price setting *at times*, but both of these influences will be captured in JKM *at all times*.

Consideration of International Reference Price Markers

Title Transfer Facility (TTF)

Typically the marginal LNG transaction into Asia will be priced in relation to the European Title Transfer Facility (TTF) hub price, plus a differential which accounts for the additional shipping cost between Europe and Asia. Therefore, TTF and shipping costs are key influences on JKM price formation for much of the year.

On that basis any seasonal influence of TTF on JKM is captured in the JKM price assessment, until the point that Asian fundamentals require US LNG to meet marginal demand, which decouples this price correlation. Given this strong correlation between JKM and TTF throughout most of the year, ECGM domestic market buyers could consider trading around TTF and freight futures to hedge and cover any JKM-related positions entered into.

Henry Hub "Plus"

Any argument for the use of US LNG pricing as the Reference Price Marker in the netback calculation would need to incorporate the additional fees charged by US LNG projects to bring its feedgas to market (Henry Hub "plus"). This includes a margin to cover gas procurement, liquefaction and shipping (typically 115% of Henry Hub) plus the relevant freight costs to North Asia.

Henry Hub-linked LNG is only the marginal supplier into the Asian spot market during periods where the JKM price signals are sufficient to cover its higher marginal costs (due to its greater shipping distance and feedgas costs). More typically the marginal supplier of LNG into Asia will be priced in relation to the European Title Transfer Facility (TTF) hub price, plus a differential which accounts for the additional shipping cost between Europe and Asia.

Any seasonal influence of US LNG (Henry Hub "plus" shipping differential to North Asia) is already captured in JKM price assessments at the margin (see above).

This should also be considered in the context that Henry Hub-linked LNG will continue have limited (minority) market share in North Asian and its growing influence over recent years will likely be capped by growth in Qatari, African and Asia Pacific LNG supply, which will be predominantly backed by oil-indexed contracts.

Using Henry Hub as the Reference Price Marker would not align with the opportunity cost framework under which the LNG Netback Series provides price formation transparency to the domestic market. Queensland exporters do not sell gas on a Henry Hub-linked basis and Henry Hub prices are set by North American supply and demand fundamentals. These alone have little relevance to LNG price setting in North Asia or consequently Australia.

Henry Hub-linked LNG is only the marginal supplier into Asia during periods where the JKM price signals are sufficient to cover its higher costs into Asia (due to its greater shipping distance and feedgas costs). As identified in this review, typically the marginal supplier of LNG into Asia will be priced in relation to TTF, plus a differential which accounts for the additional shipping cost between Europe and Asia.

Additional Methodological Considerations

Following a review of different elements of the netback calculation, we do not believe there are additional considerations that need covered. There may be slight differences in each Queensland LNG producer's cost structures and positions around shipping which influence its decisions around gas sales but simplification of these into a single applicable methodology outweighs any marginal accuracy benefits gained through introducing additional complexity. We do however support an update of plant efficiency assumptions based upon latest production data provided to ACCC by the Queensland LNG producers.

LNG Netback influence on Domestic Market Pricing

One point to recognise is that the LNG netback is just one element of influence on what may set domestic gas pricing in the ECGM. Based upon review submissions to ACCC, this point may not be clear among all market participants. Development of a reliable domestic price marker essentially requires a liquid fully traded gas hub in the ECGM.

At best JKM benchmarks the minimum price that a gas producer might sell gas to a domestic buyer, accounting for its own view of how commodity prices (including JKM), production costs and foreign exchange might evolve over the proposed contract period.

A more appropriate price marker comparison for longer-term gas sales might be short-term spot LNG contract ('strips') or long-term LNG contract formula. We would expect both of these to be priced off or heavily influenced by an oil-index mechanism, which remains the dominant price marker for Asian LNG contracts in 2021. Nevertheless, the influence and incorporation of JKM elements into longer-term LNG contracts is a growing trend which is expected to continue over the coming years.

Increasing the Forecast Period of the LNG Netback Series

The ACCC has ambitions to extend forward the timeframe of the Netback Series to provide longer-term transparency to influences on domestic gas contracting (2+ year duration gas sales agreements). A balance needs to be struck between the additional transparency of providing a longer-term data series and the quality of these forecasts so that these might be useful to long-term planning decisions.

Most of the forecast data of the LNG Netback Series (e.g. JKM, freight costs) are based upon qualitative data (expert opinion) though JKM futures are based, at least in part, on settled financial trades. These are informed projections based on current data but are focused on identifying near term outcomes (<2 years). The further out the forecast period extends, the less relevant this starting data set may be to longer-term projected values. This will likely lead to greater uncertainties over the quality of forecasts and therefore lower reliance as a decision support tool.

Oil-linked pricing in LNG contracts is used for longer term LNG contracts (2-20 years), although price review clauses (e.g. every 3-5 years) can result in adjustments to the oil-linkage formula to bring it back into line with prevailing market rates. Oil-linked contracts also enable parties to hedge against variability in the oil price component of these.

Whilst the JKM LNG netback price provides a relevant price marker to the ECGM in the short term (up to 24 months), an oil-linked LNG netback price marker may provide ECGM gas buyers with a more comparative price marker for their longer duration contracts. That said, as the JKM market develops over time and increasing becomes as feature of longer-term deals, the relevance of the oil-linked marker on the ECGM may diminish.

Other influences on domestic market prices also become more relevant in the longer-term, than short-term JKM spot price signals. These include the cost of supply (including potential LNG imports), policy decisions and longer-term supply and demand fundamentals.

There are viable approaches and methodologies to extend the forecast period of other components of the netback calculation . For example, a long term view of freight charter rates could be developed through access to brokers or marker commentator assessments or by calculating an appropriate forecast based on the cost and depreciation schedules for new build vessels.

Further investigation of these will be considered based upon the feedback received through the consultation period of this review.

2. Global Gas/LNG Market Considerations

This segment characterises the key features of the current global gas and LNG market and their relevance to East Coast Gas Market (ECGM) participants. It summarises some of the key trends and factors which influence international gas pricing and are relevant to Netback Series.

2.1. Gas/LNG demand and LNG liquefaction capacity

2.1.1. Gas/LNG demand

Section Summary

- Global gas demand growth is growing across all regions except Europe throughout 2021-2030
- Overall global LNG demand growth outpaces gas growth during the same period
- Gas demand in Asia is expected to largely remain resilient to energy transition trends in the period to 2030
- Key market - Asian gas and LNG demand is growing faster than RoW out to 2030 and beyond

2.1.1.1. Global gas/LNG demand

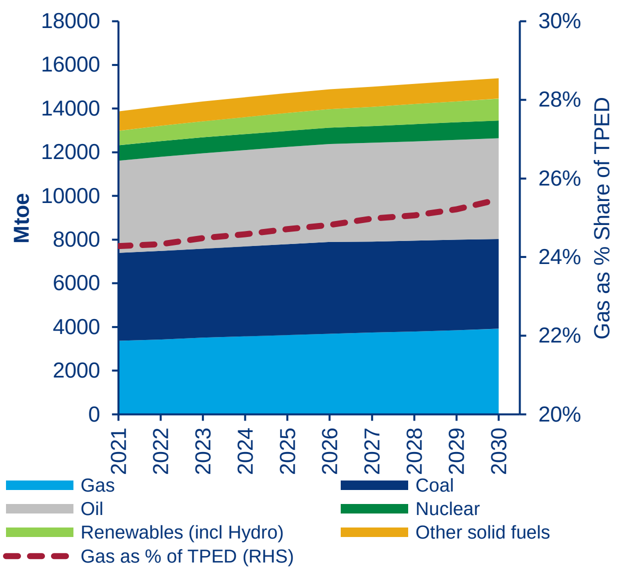
Gas

Gas is expected to make up over 24% of global total primary energy demand in 2021. Global gas demand growth is forecast to grow at a compound annual growth rate (CAGR) of 1.7% between 2021 and 2030. The bulk of this demand growth will occur in China, South Asia and Southeast Asia.

A lack of commercially viable alternative fuels should ensure that natural gas remains resilient in the industrial and heating sector globally. In the power sector, declining nuclear and coal capacity provide support for gas growth across the world, despite booming renewable investments. Though Europe's stronger decarbonisation agenda will likely see gas start to decline this decade.

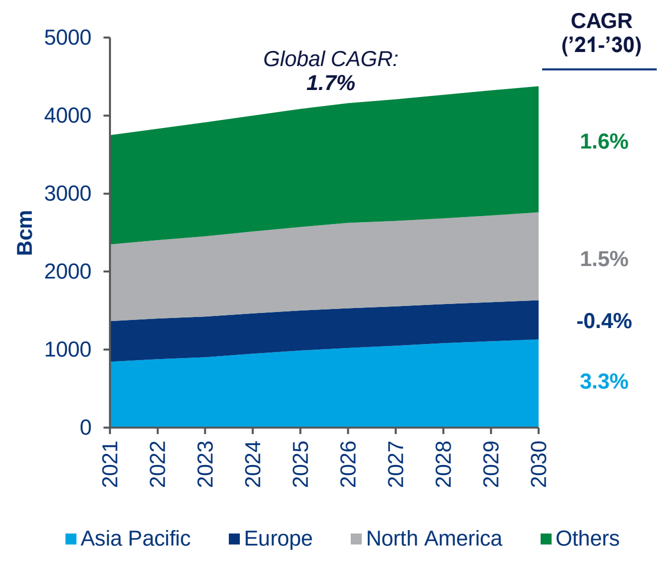
In Asia, where coal accounts for more than 50% of the energy supply mix, there is scope for strong gas demand growth through coal-to-gas switching as gas remains key in achieving carbon reduction targets and security of supply. This also applies to the industrial and heating sectors where gas accounts for only 10% of demand in this sector in Asia and has more headroom for growth.

Figure 1: Total Primary Energy Demand (2021-2030)



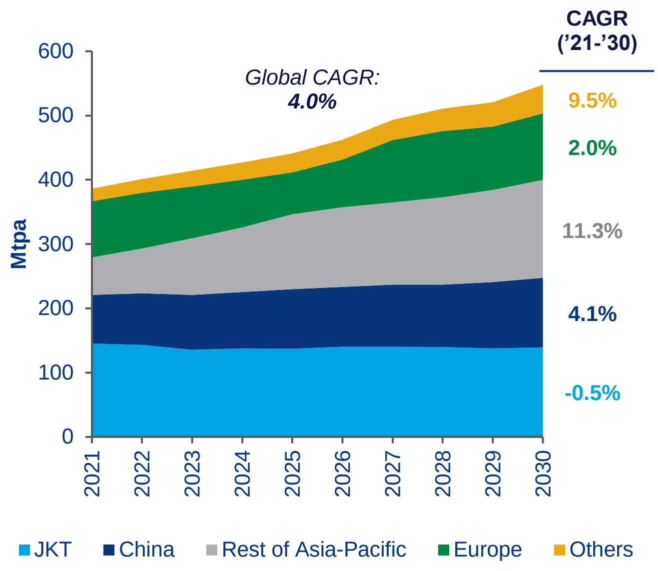
Source: Wood Mackenzie

Figure 2: Global Gas Demand by Region (2021-2030)



Source: Wood Mackenzie

Figure 3: Global LNG Demand by Region (2021-2030)



Source: Wood Mackenzie

LNG

Global LNG demand growth will outpace gas demand growth, with a CAGR of 4.0% between 2021-2030. This is largely due to declining domestic gas production in importing countries which will see LNG meet a greater share of gas requirements in these markets. This will be complemented by demand growth for LNG in other sectors such as LNG marine bunkering and other industrial and transport applications. Global LNG demand is forecast to increase by over 160 Mtpa through the current decade (to 2030).

New LNG markets continue to emerge and further underpin LNG's growth opportunities. In 2020, 42 countries had imported LNG, up from 34 in 2015. Other emerging features of the LNG market as it continues to evolve from a traditional bilateral sales model to include greater short-term trading, supply chain optimization, and greater flexibility and liquidity, particularly on the supply side.

2.1.1.2. Asia Gas/LNG demand

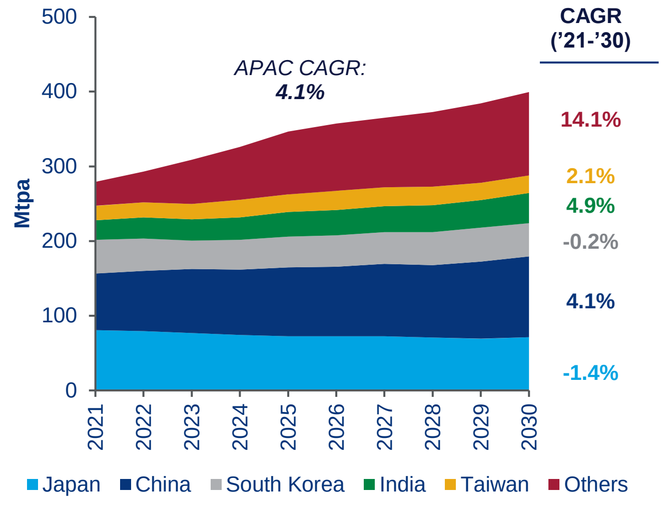
Demand for new LNG supply will grow across the Asia Pacific region, from the core gas demand growth markets of China, South and Southeast Asia, but also through growing uncontracted or underlying demand in the more mature markets of Japan, Korea and Taiwan.

LNG is set to play a bigger role in Southeast Asia's gas mix while a number of new countries are forecast to join the LNG importers club in the 2020s which will buoy regional LNG requirements. Myanmar became the world's newest LNG importer in 2020 and Wood Mackenzie expects Vietnam and Philippines to become LNG importers through the current decade.

Regas infrastructure development and gas market reforms will play an important role in the pace of this sub-regional LNG demand growth.

This highlights the importance of policy and gas advocacy on future Asian gas/LNG demand, as its economies think about decarbonisation and the energy transition.

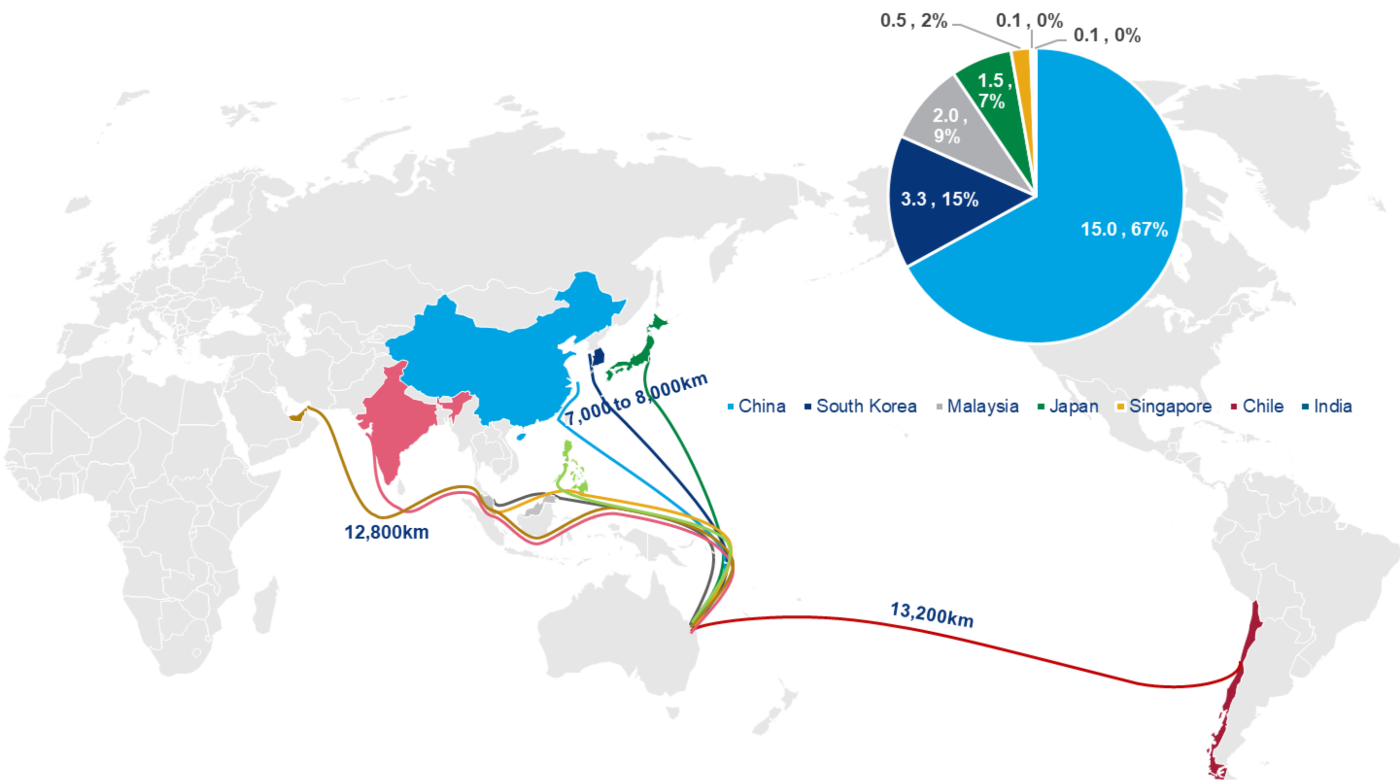
Figure 4: APAC LNG Demand by Country (2021-2030)



Source: Wood Mackenzie

The Asia Pacific LNG market is the key market for Queensland LNG exports. China, South Korea, Malaysia and Japan accounted for ~98% of the 2020 delivered supply with underlying contracted LNG volumes with the customers in these markets driving the majority of this supply.

Figure 5: Queensland LNG exports by Country



Pie chart illustrates 2020 LNG export volumes and destination country % share
Source: Gladstone Ports Corporation and Wood Mackenzie

2.1.2. LNG capacity/supply

Section Summary

- Strong growth in LNG supply since 2018, with the US, in particular, seeing substantial growth in LNG liquefaction capacity over 2019 and 2020.
- Strong future supply growth from Qatar, Russia, Africa and Asia through 2025-2030 will rebalance geographical splits of new LNG supply growth, away from mainly US.
- Long-term (LT) SPAs are needed to underpin the investment rationale for these new projects, Brent oil-linked or HH-linked agreements remain important to secure financing.
- Existing supply is depleting, further highlighting the need for new supply development.
- Existing Asia-destined supply capacity is becoming increasingly uncontracted through 2030.
- Not all supply from an LNG supply project is typically fully contracted and flexibility is maintained for spot and short-term supply trades.

2.1.2.1. Global LNG supply

Both operational and committed future global LNG supply capacity have grown significantly since the ACCC LNG Netback Series was launched in 2018. Even with robust underlying gas and LNG demand through the intervening period, the market has at times struggled to absorb all of this additional supply capacity.

Since the ACCC LNG Netback Series was launched, many global LNG supply trends have evolved, some of which confirmed earlier expectations but also others that were unanticipated:

- US LNG growth has accounted for the majority of new LNG supply additions (e.g. 50% in 2020) and therefore this has increased overall share of Henry Hub-linked LNG volumes.
- US LNG market share of total global supply capacity has risen from zero to around 16% between 2016-2021, though this growth is expected to plateau at between 20-25% of global market over the coming decade as new projects from Qatar, Russia, East Africa and Australasia come to market.
- US LNG has experienced curtailment during periods of low prices – due to its flexibility and 'at the margin' short-run costs and project structure (US LNG typically has the highest short-run marginal cost of LNG supply in the market).
- LNG project sanctions have continued apace with 2018 and 2019 proving record years for new capacity Final Investment Decisions (FID). This will result in a new wave of LNG (80-120 Mtpa) hitting the markets between 2023 and 2026 (including Qatar which sanctioned the world's largest ever LNG project in early 2021).
- A sharp slowdown in LNG FIDs in 2020 will provide respite, though a new wave of projects (both US and RoW) is well placed to proceed in 2022 and 2023 and would hit the market in the latter part of the current decade. This will fill a supply gap that we anticipate would otherwise be more than 40 Mtpa by 2030 (equivalent to approximately 5% of current market).

LNG supply growth dynamics

Against expectations, annual global LNG production grew during 2020 (+0.4%) despite demand destruction and supply curtailments due to COVID-19.

Supply growth in the medium term will average ~4% CAGR through to 2025. The return of operational facilities to full utilisation will drive near-term growth, while the commissioning of a number of under-construction LNG facilities will add capacity in the medium term. LNG supply growth will likely again accelerate between 2025 and 2027, as the market absorbs the ~125 Mtpa of LNG which took FID between late 2018 and Q1 2021.

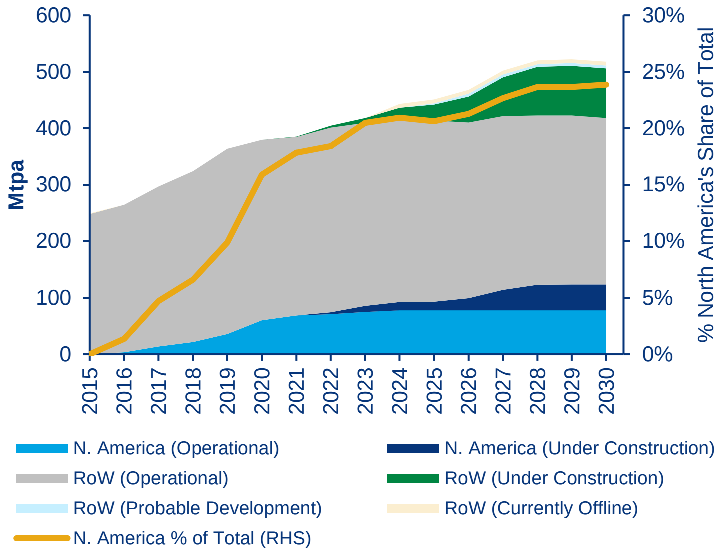
The timing for new LNG supply is ~3 to 5 years from FID for a project and contracts supporting that FID need to be negotiated and executed beforehand (can take 1-3 years). This new LNG supply will require financing off oil-linked (Brent) or Henry Hub-linked contracts (given the large capital investment required to develop new LNG supply) this is because futures can be hedged to ensure cashflows to cover financing.

US LNG supply has secured significant global market share between 2016 and 2021 (17.8%), like Australia (2014-2017) and Qatar did before it (2009-2012).

While US LNG has dominated recent supply capacity additions between 2018 and 2020, there will likely be a rebalance in this concentration of supply from expansions near large resources through this decade. Russia, Qatar, East Africa and Australasia (incl. PNG) together with some additional US, will dominate the long-term landscape, supporting continued growth in global LNG demand, particularly across Asia. That said, by 2023 the US will temporarily become the largest LNG supplier in the world by volume (exceeding 85 Mtpa), until Qatar overtakes in 2025. US market share of total global supply capacity will increase to ~20-25%.

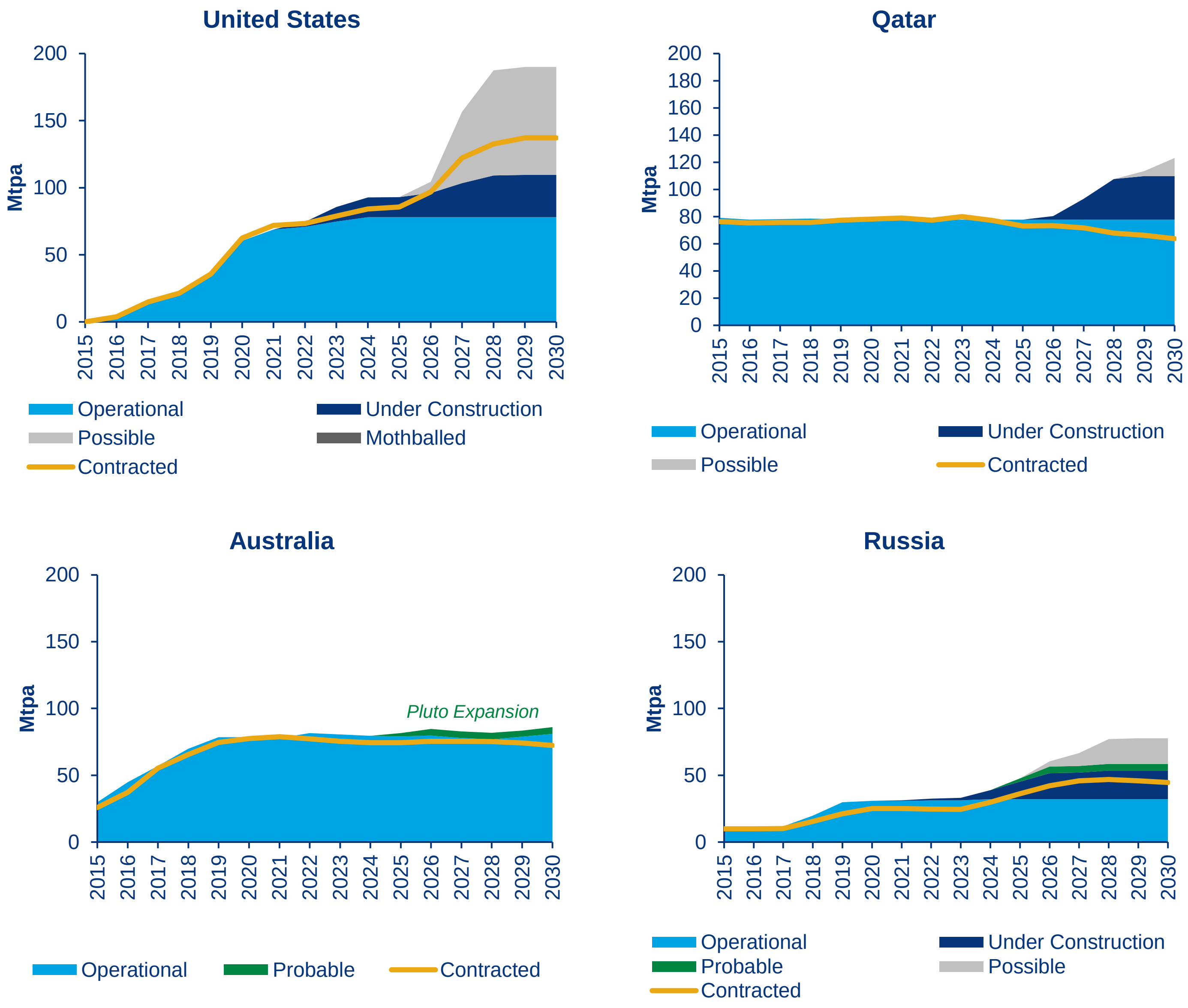
United States, Qatar, Australia, and Russia are expected to hold the largest liquefaction capacity in 2030.

Figure 6: LNG Effective Capacity Outlook (North America vs. RoW)*



*Note(s): * includes only operational, under construction, and probable supply*
Source: Wood Mackenzie

Figure 7: LNG Capacity Outlook of Key Countries by Development Status and Contracted Volumes*



*Note(s): * includes all contract/agreement types (SPA, secondary SPAs, HOA, MOU, options)*
Source: Wood Mackenzie

2.2. Trade and market trends

Section Summary – Trade and Market Balance

- LNG markets continue to experience a period of oversupply, exacerbated by the impacts of COVID-19 pandemic in 2020/2021.
- Implications of this have included generally lower prices (spot and term) and higher volatility.
- The LNG market has been rebalancing through 2021 as demand recovers post-pandemic. Asian spot prices have risen from US$2.00 in summer 2020 to US$10/mmbtu in summer 2021 as Brent oil price also recovers from US$40 to US$75/bbl.
- The LNG market is expected to further rebalance resulting in a tightening around 2025 which will drive up prices to the cost of new supply.
- There is growing trade in LNG spot markets. This in part reflects the growth in LNG portfolio players and more supply liquidity in the market through US capacity build.
- Expected growth in share of spot/short-term volumes in the LNG market, tempered by the requirement for new supply development which requires contractual arrangements to secure financing.
- The ECGM remains linked to North Asia LNG markets as the alternative supply option (to the domestic gas market) for Queensland LNG exporters.

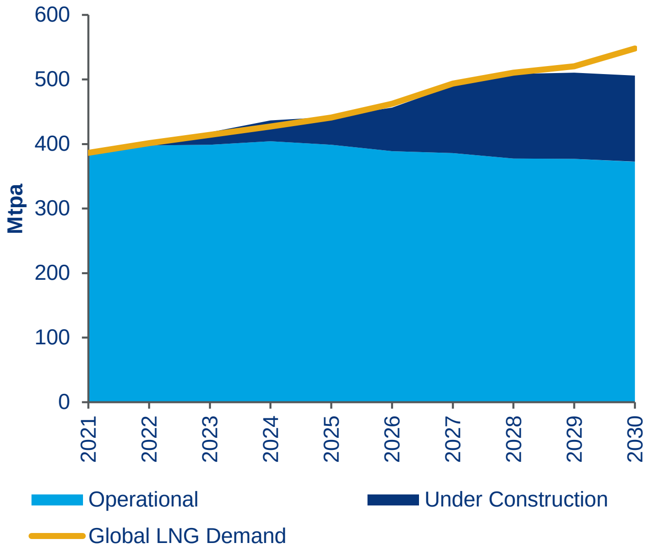
Future supply and demand dynamics are by nature speculative and views on these will differ across individual market participants.

Wood Mackenzie's market outlook shows that in the period out to 2028, new supply capacity is expected to come from projects which are already under-construction. These will contribute an additional LNG output of ~67 Mtpa by 2026.

New LNG supply is likely required to meet the expected growth in Asia Pacific LNG demand from 2027-28 onwards, yet the pace and scale of that growth is dependent on the progress made by projects currently vying for FID and will have implications for future LNG market dynamics and pricing trends.

Where this supply growth originates from also has the potential to strengthen market liquidity and with it the acceptance of spot and hub price indexation in longer-term contracts (e.g. if the share of flexible and/or US LNG increases as a percentage of total global supply.)

Figure 8: Global LNG Supply/Demand Balance (2021-2030)



Source: Wood Mackenzie

Note, the three Queensland LNG export projects account for ~5.6% global LNG supply (2021).

2.2.2. Global LNG contracting trends

The majority of Asia-destined LNG is sold on LT contracts, principally indexed to oil. Asian buyers historically contracted oil-linked LNG supply, though some larger LNG buyers (utilities, traders and end-users) have entered into Henry Hub-linked contracts. These are on an FOB basis that provides the buyers the flexibility over the destination market they supply.

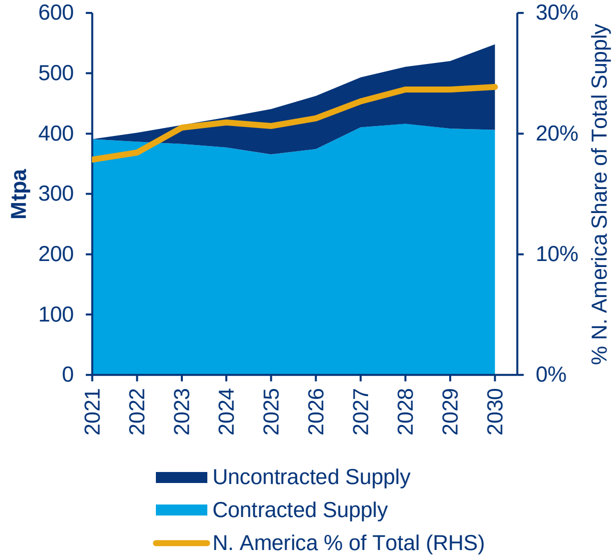
These makes up a smaller portion of their supply portfolio and therefore their risk exposure to Henry Hub price movements from a portfolio perspective is still relatively small and usually up to around 20-30% of a few portfolio players.

Not all LNG buyers can take on Henry Hub price exposure risk and there are limits to how much Henry Hub the larger utilities can take. Portfolio market players who have flexibility to move LNG between Europe and Asia and therefore will have more appetite for Henry Hub-linked pricing. Whilst these buyers have contracted on a Henry hub-linked basis, on-sales are at JKM or a TTF (minus regasification) price.

The expected growth in LNG demand will need new supply projects which typically require long-term Brent oil-linked or Henry Hub-linked contracts in order to be financed and built. Project developers outside of the US will sell these projects on a predominantly Brent oil-linked basis.

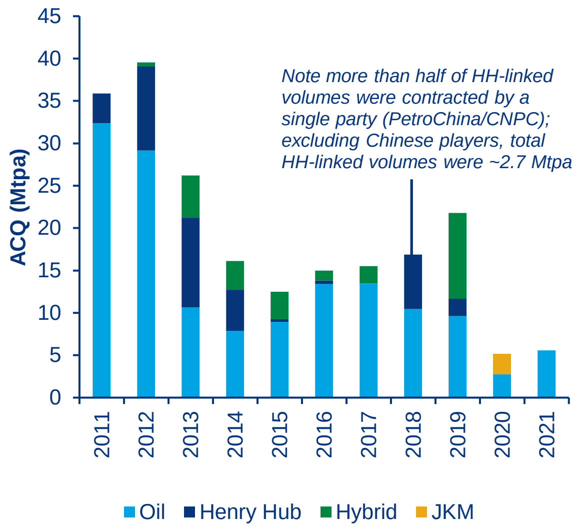
Over the past 4-5 years, an increase in alternative (to oil) pricing mechanisms has been observed (such as JKM and TTF indexation) in new APAC contracts. This has been driven by buyer needs to diversify their pricing exposure and/or optimise via interregional arbitrage.

Figure 9: Global Contracted vs. Uncontracted Supply



Source: Wood Mackenzie, includes assumptions over new project FIDs which may or may not eventuate. Actual % NA supply may be lower.

Figure 10: LNG Contracts by Year Signed/ Price Indexation (Asia-Pacific)



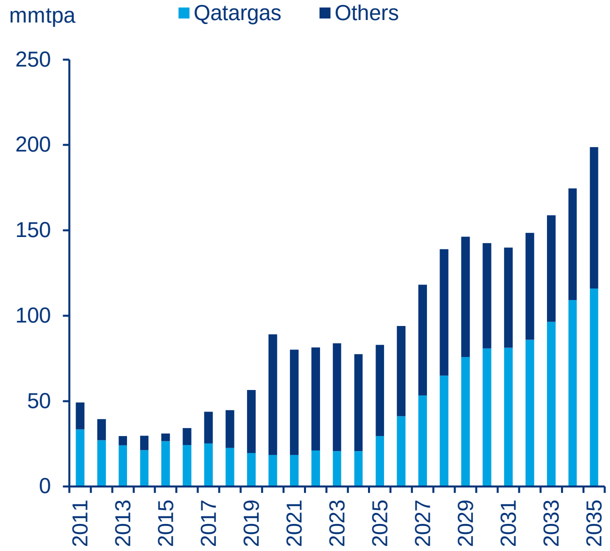
Source: Wood Mackenzie, note Annual Contract Quantities

Other trade and contracting dynamics

The proportion of LNG sold into spot markets has increased significantly in recent years, increasing from 10% of total trade in 2011 to about 35% per cent of the market in 2020. This global trend is expected to continue as flexible LNG volumes within major LNG portfolios continues to add to global LNG supply liquidity.

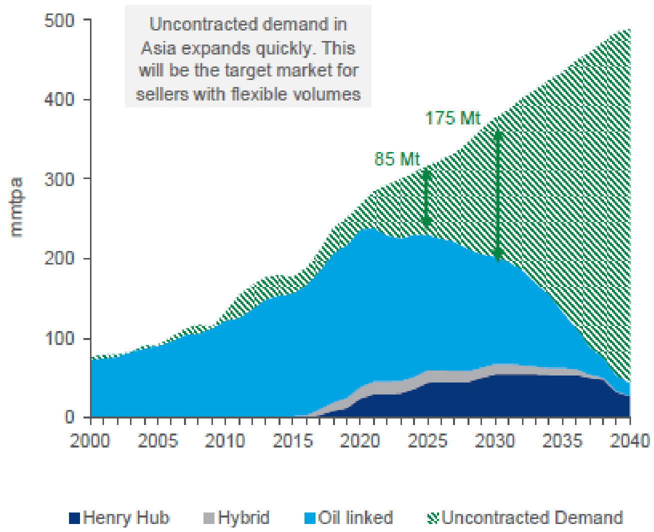
This global trend is less pronounced in Asia, where spot trade remains a smaller share of Asian buyers' procurement strategies and long-term contracts continue to dominate. However, as legacy contracts expire, some may be replaced by shorter-term contracts or greater reliance on the spot market through time. This trend to increasing spot trades is likely to be tempered somewhat by the requirement for new supply developments still requiring term (longer-duration) contract arrangements to support new supply developments. Therefore, whilst it is expected that spot trade will continue to grow in influence in Asia, it is unlikely to form the majority of LNG trade in the region in this decade.

Figure 11: Flexible LNG within Major LNG Portfolios*



Note: includes pre-FID projects, Others includes major LNG players with portfolio volumes*
Source: Wood Mackenzie

Figure 12: Contracted/uncontracted LNG Demand in Asia



Source: Wood Mackenzie

An increase in flexible and uncontracted LNG volumes, more flexible contract terms and increasing trade by LNG portfolio traders, suggest that the spot trading and liquidity will continue to grow. This growth in liquidity may have broader implications for future LNG spot market pricing trends. The number of spot LNG cargoes deliveries into China, on an annual basis, has increased substantially over the ten years to 2019. Unsurprisingly, Europe has also seen significant growth in LNG spot imports. This likely reflects Europe's ability to absorb LNG spot cargoes, due to the liquidity of TTF.

Oil will continue to feature predominantly in LNG (term and strip) contracts, although there has been a number of hybrid deals structured around both Brent oil-linked and TTF indexation. For instance, state-owned company China National Offshore Oil (CNOOC) indicated it would use part Brent oil-linked and TTF indexation in its 13-year 1.5 Mtpa deal from Mozambique.

JKM as a marker in long-term contracts

JKM has been emerging as a more reliably traded marker in recent years. One of the first long-term LNG contracts linked to JKM was announced in December 2020 between Santos and Diamond Gas International (Mitsubishi). JKM will likely become more influential as a regional marker, as market players get more comfortable with its liquidity and Futures tradability (see **Section 4**).

3. ECGM market considerations

Section Summary

ECGM supply/demand fundamentals

- AEMO expects ECGM demand to remain robust over the coming decade, though conventional supply is declining and gas supply from Queensland is increasingly required to balance the market.
- ECGM is likely to remain structurally short of supply as long as there is under-utilised export capacity at Gladstone.
- LNG supply volumes out of Queensland will be critical to balancing the Asian market through the coming decade. Queensland LNG exporters will continue to have strong demand opportunities for spot/short-to-long term LNG volume sales if gas supply is available for export.
- This inextricably links the ECGM with the LNG export market and underpins the rationale for LNG netback pricing to be a consideration in domestic gas price discovery, together with cost of upstream supply.
- Dynamics of Southern ECGM may require additional investigation with regard to this review (particularly with respect to the potential development of an LNG import terminal).

Gas sales

- 95%+ of ECGM gas is sold on term (2-20yr) contracts, with the balance traded on the spot/short-term market. Domestic gas contracts are bilateral buyer/seller agreements – with fixed price or oil-linked formula (Brent), with a few contracts linked to JKM.
- ECGM spot/short-term trade is still very small and illiquid. Gas hub pricing is not expected to evolve quickly nor see significant additional volume depth at Wallumbilla in the coming decade due to the small number of gas buyers and sellers in the ECGM.
- Domestic gas price formation reflects a basket of influential factors, not least the underlying cost of developing new supply.
- Southern ECGM gas sales incur other market specific costs which may distort the relevance of the LNG netback.

Market reforms

- ADGSM and LNG Producers' HoA are designed to improve gas supply availability to the ECGM gas buyers. ADGSM may ultimately distort price relationships of the LNG Netback Series.

3.1. ECGM Fundamentals

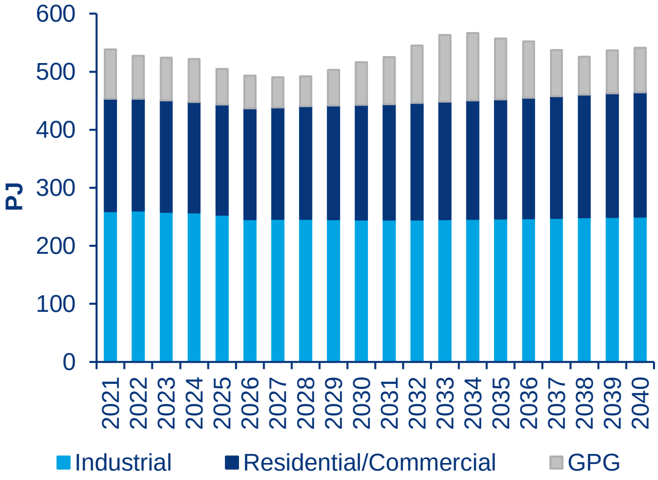
This section aims to provide context to the ACCC review by identifying some of the key specific considerations of the ECGM which may be relevant to the future direction/enhancements to the LNG Netback Series. It also builds on the prior LNG market dynamics section to highlight where there are direct and indirect impacts from international gas markets on the ECGM. These may include (not exhaustive):

- domestic price setting;
- contract term requirements for supply;
- cost of supply; and/or
- how gas producers consider gas sales decisions (export vs domestic).

3.1.1. ECGM demand considerations

AEMO forecasts ECGM domestic gas demand to remain broadly flat over the period to 2030. Gas-fired generation has the most demand uncertainty as gas provides the flexibility to support the growth in variable renewable energy and help offset retirement of coal-generation plants.

Figure 13: ECGM Gas Consumption Outlook



Source: AEMO GSOO 2021

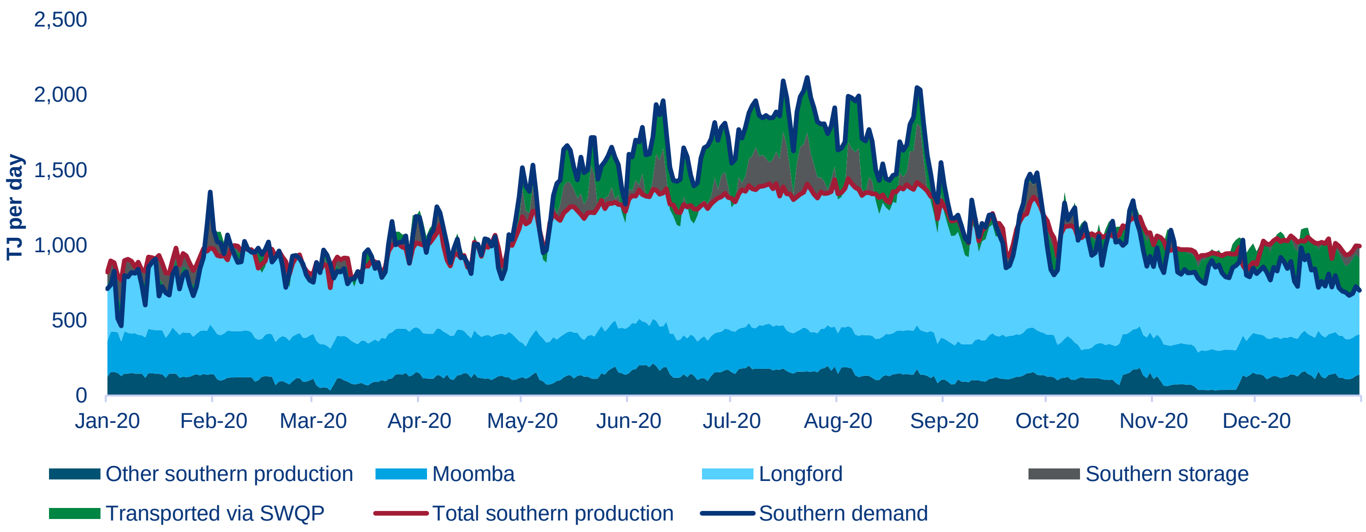
Industrial demand. Industrial demand accounts for the largest portion of domestic gas usage on the east coast (~48%). Industrial gas demand is characterised by broadly consistent daily demand across a year.

Residential/commercial. Residential demand accounts for ~36% of domestic demand but displays high seasonal variability due to heating demand - most prominent in the southern states.

Gas-fired power generation (GPG). GPG remains a volatile consumer of gas – across the year as well as from year to year. GPG provides a firming function to fill periods of low renewable electricity supply and can substitute for lost coal-fired generation during periods of outages (planned or unplanned) or (in part) coal-fired plant retirement.

The southern ECGM (southern states of NSW, SA, Victoria and Tasmania) accounts for the majority of gas demand and is highly seasonal. This requires a substantial increase in winter gas supply which is currently supported from a mix of increased production, gas flows (south) from Queensland and gas storage.

Figure 14: ECGM Gas Southern Supply/Demand



Source: AEMO 2021 GSOO

3.1.2. ECGM supply considerations

For many decades the ECGM has predominantly been supplied from conventional gas fields (Gippsland, Bass, Otway and Cooper basins). As conventional gas production enters into decline, new supply challenges to meeting the southern Australia gas market needs have arisen. The development of the Queensland LNG projects resulted in a large increase in the development and production of coal-seam gas (CSG) in Queensland. Whilst Queensland CSG gas supply has increased dramatically, a corresponding increase in gas demand has been created by the LNG export projects. Queensland gas supply (via the SWQP) is required to provide support to the southern markets, particularly in the high demand winter months (acts as marginal supplier). These challenges have created an overall tighter domestic supply/demand dynamic for the ECGM.

In addition to the tighter supply/demand dynamics, the majority of gas supply remains concentrated to a relatively small number of domestic gas sellers and the three Queensland LNG export project joint ventures. Whilst new supply from additional producers has come to market in recent years (e.g. Cooper Energy and Senex), the volumes remain relatively small. Supply competition therefore remains a key challenge for the ECGM.

Concerns for gas supply security has resulted in the Australian Government implementing the ADGSM and the operators of the Queensland LNG export projects entering into a Heads of Agreement (HoA) with the Australian Government to ensure adequate gas supply is made available to the ECGM. The HoA commits the Queensland LNG exporters to offer uncontracted gas to the domestic market first on competitive market terms before it is exported (until 2023). This is a similar agreement to make gas available to the domestic market that the LNG exporters committed to in 2018.

3.1.3. ECGM infrastructure considerations

The increasing demand for Queensland gas supply into the southern states (Victoria, NSW and SA), has the potential to create flow constraints, particularly in winter peak demand months.

In addition to the transportation differential created by this draw on supply, additional costs in servicing the winter peak demand (storage costs) add to the cost of supply in the southern states relative to Queensland. This could create separation in pricing between the north and south markets during peak demand periods as the pipeline infrastructure becomes constrained.

Concerns around pipeline constraints limiting southern gas flows, have led to LNG import terminal(s) being proposed. Recently announced commitments to expand the South-West Queensland Pipeline (SWQP) will provide some relief and potentially push out the need for LNG imports for a few more years (APA-Origin Energy deal, announced 5 May 2021).

Whilst there is potential for new supply to come from existing producing areas, the prospect of material new sources are limited in the short-to-medium term. Material, new gas supply areas will require new pipeline developments to bring gas from more distant locations to support the ECGM supply in the longer term (e.g. Northern Bowen Basin, Galilee Basin and/or Beetaloo Basin).

3.1.4. Gas sales in ECGM considerations

Gas buyers in the ECGM can be characterised into three main groups:

- Retailer/Generator/Aggregators (e.g. Origin Energy, AGL, Energy Australia, Engie, Alinta etc.).
- Large Industrials/Mining/Mineral Processing (e.g. Incitec Pivot, Orica, Qenos, Rio Tinto, QAL, Glencore, etc.).
- Industrial/Manufacturers (e.g. Visy, Orora, CSR etc.).

Each of these domestic gas buyer groups have different supply requirements:

- Retailer/Generator/Aggregators have large volume requirements with daily and seasonal variability in their demand needs. They have multiple locations for demand (multi-state delivery points). The Retailer/Generator/Aggregator demand over the medium and longer term is uncertain as they may lose or gain customers due to competition and have changing demand for gas generation.

- Large Industrials/Mining/Mineral Processing gas buyers have large volume demand requirements and relatively consistent daily volume requirements. They are generally large single site operations (although a buyer may have multiple operations e.g. Incitec Pivot Gibson Island, Phosphate Hill and Moranbah Ammonia Nitrate operations are in three discrete geographic areas in Queensland). These operations are generally long-life (>20 years) operations and therefore their gas needs remain relatively consistent over the longer term.

- Industrial/Manufactures may have relatively consistent daily gas demand operations at multiple sites and across states. These gas buyers operations can be long-dated but they also have competition with imports.

As a result of these demand variances between gas buyers, their gas supply needs are also different, including:

- Supply point relative to delivery point;
- Level of swing required from supply to meet demand variability; and
- Uncertainty around demand level over the medium and long term.

Meeting Southern ECGM seasonality incurs additional measures and costs (transport, storage, production shaping) which are or may in future be reflected in the terms and conditions and pricing of sales agreements.

3.1.5. ECGM gas buyer requirements

Retailer/Generator/Aggregators generally have a portfolio of gas supplies from multiple locations to serve their needs. They tend to contract the majority of their volumes for the short to medium term (2 to 5 years) as they have less certainty around their demand requirements over the longer term (customer churn and power demand uncertainty). They will manage short term variances and imbalances with storage and short-term gas purchases, including spot purchases.

Large Industrials/Mining/Mineral Processors require long-term supply certainty and therefore will tend to require gas contracts with longer terms (>5 years, some up to 20 years). These buyers will tend to purchase from a single supply location for each of their operation sites.

Industrial/Manufacturers require gas supply certainty over the medium term and potentially into the long term for their operations. They will therefore prefer gas supply with a term >2 years.

Gas price is a critical component to the ECGM gas buyers contracting strategy. However, the needs of buyers in terms of volume, duration of contract and location and shaping of supply is different across buyer groups. In general, buyers have a preference for medium to long-term contracted supply (>2 years). The LNG Netback series referencing JKM (short-term pricing signal) may therefore not meet the needs of all ECGM gas buyers.

3.2. Queensland LNG Exports within the Global & APAC Context

Queensland has three LNG export projects, all located in Gladstone, with a combined nameplate capacity of ~25.3 Mtpa. These projects export ~21-22 Mtpa under long-term contract to a mix of Asian Utilities (Sinopec, KOGAS, Kansai Electric) and LNG portfolio companies (Shell and PETRONAS) with LNG sales in China, Singapore, Chile and Japan.

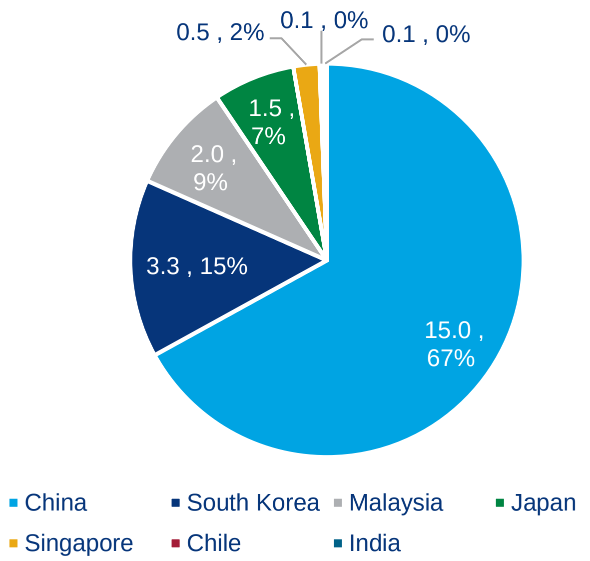
Additional LNG volumes are sold on a spot and term basis and the projects have under-utilised liquefaction capacity to sell additional volumes in the future (subject to supply availability). The Queensland LNG projects produced ~22.4Mtpa of LNG, in aggregate, in 2020.

The three Queensland LNG export projects account for ~5.6% of global LNG supply (2021). They will meet ~7.5% of Asia Pacific LNG demand in 2021. APLNG and QCLNG have supply flexibility to contribute supply to the domestic gas market above the long-term LNG contracted positions. GLNG supply position remains less certain, which limits its supply availability above LNG contracts (and existing domestic contracts) to supply additional volumes to the domestic gas market.

The use of LNG netback price links the ECGM to the North Asia LNG market as the proxy for the selling point for potential additional LNG sales from the Queensland LNG exporters. The North Asia LNG market is relatively proximal to Gladstone (relative to other LNG market locations), is the region of substantial LNG demand (China, Japan, South Korea and Taiwan) and will remain important for LNG supply as existing contracted supply expires and new contracts are entered into to meet existing demand as well as growth.

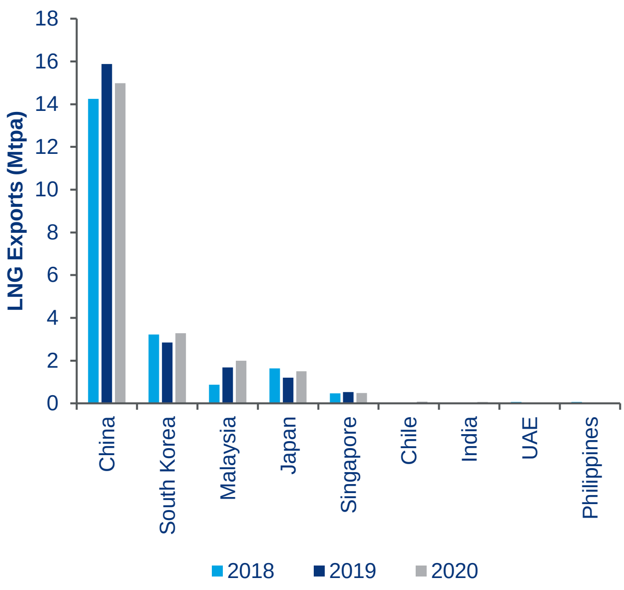
Queensland LNG's main contracted export market is China and there are significant sales to Japan and South Korea. This warrants the use of the North Asia JKM benchmark as a proxy for spot sales despite some volumes flowing to Southeast Asia, Middle East and South America.

Figure 15: QLD LNG Exports by Country in 2020 (Million Tonnes, % share)



Source: Gladstone Ports Corporation

Figure 16: Queensland LNG Exports by Country in 2018, 2019 and 2020 (Mtpa)



Source: Gladstone Ports Corporation

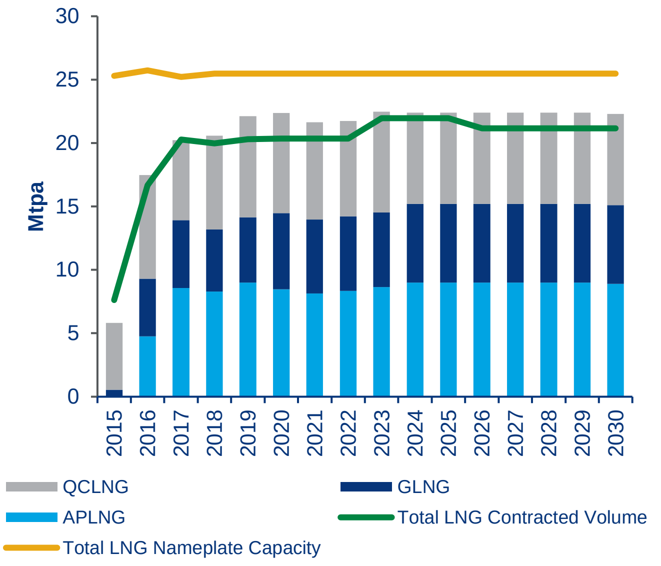
While the ACCC Netback Series does not differentiate between each project in its current netback approach, there may be different starting positions worthy of further investigation:

APLNG. The APLNG project has a nameplate LNG capacity of 9.0 Mtpa. APLNG has long-term LNG contracts for the supply of ~8.6 Mtpa through to 2035. We forecast APLNG output in the range 8 to 9 Mtpa in the period to 2030. In 2020 APLNG exported 1.1 Mt of spot LNG and supplied 180 PJ gas into the domestic market.

GLNG. The GLNG project has a nameplate LNG capacity of ~7.8 Mtpa. GLNG has long-term contracts for the supply of ~6.0 Mtpa. GLNG production has been constrained by the availability of feedstock supply. Based on current supply availability to the project, Wood Mackenzie forecasts the GLNG project will produce at ~6.0 Mtpa through to 2030. In 2020 GLNG is estimated to have supplied less than 0.3 Mt of spot LNG, and supplied 58 PJ of gas into domestic market.

QCLNG. The QCLNG project has a nameplate LNG capacity of 8.5 Mtpa. Shell is the offtaker of the LNG from QCLNG utilising the LNG for its portfolio of supply. Wood Mackenzie understand that QCLNG contracted LNG output is ~7.2 Mtpa. In 2020 QCLNG is believed to have exported nearly 0.8Mt of spot and an estimated ~75 PJ into the domestic market.

Figure 17: ECGM LNG Output, Capacity, Contracted Volume



Source: Wood Mackenzie

Fundamentally, with spare LNG capacity at Gladstone, the Queensland LNG producers have an opportunity and choice, as to whether they supply LNG for export or gas to the domestic market, on a short-term basis. LNG exports could be individual spot LNG cargoes or potential strips of short to medium-term cargoes. For domestic gas supply, the LNG producer could sell into the ECGM on a spot basis or contract supply on a short, medium and/or long-term contract basis.

Longer-term decisions to export beyond current LNG contractual arrangements require greater consideration, in terms of gas resource availability and capital allocation to extract the resource (drilling and completions).

3.3. LNG Netback Considerations to ECGM

The ACCC Netback Series is based on an "Opportunity Cost Framework". The immediate opportunity for an LNG producer is a sale of an LNG spot cargo at a North Asia LNG spot price (JKM), or domestic supply at the LNG netback equivalent price (JKM minus shipping, and marginal costs) to Wallumbilla. However, for a domestic gas buyer, this "immediate" or spot price does not necessarily create price transparency with their supply "term" (typically >2 years) requirements.

The demand for and price of LNG into the North Asia LNG market will be a key influence on the ECGM as the Queensland LNG exporters' alternative market opportunity for gas/LNG (this is both the case for contracted and spot Queensland LNG exports). Spot price volatility, seasonal variations in demand and price will influence the Queensland LNG exporters decision making and the price at which they make gas available to the domestic gas market.

The two price references on which Queensland LNG is exported is on an oil-linked (term and strip contracts) and an Asia spot price (JKM equivalent) basis. Other price markers (such as Henry Hub plus or TTF) have not been referenced and are not relevant for Asian imports of Queensland LNG.

3.4. Potential LNG Import to ECGM

The potential for LNG imports into the ECGM has been proposed by a number of proponents seeking to provide additional gas supply options to support the domestic market. All proposed projects are focussed on the southern market where declining conventional gas production has seen a pull on northern gas supplies (Queensland) to meet winter demand. With further declines in conventional gas production expected, there is concern that pipeline constraints will limit gas supply from the north to the south over future winter months.

If an LNG import terminal were to be developed, this will result in another direct link to international LNG prices for the ECGM. LNG imports would change the marginal supplier from Queensland to NSW or Victorian imports.

The pricing of domestic gas would then be further influenced by the source of the contracted LNG supply (contracted LNG supply on a longer term basis plus regasification cost) and whether the facility maintains flexibility to receive shorter term volumes that are priced at spot or short term prices. If there were direct imports of US LNG, relevance of Henry Hub-linked price to the ECGM may become important (further evaluation of LNG import prices on the ECGM would be required).

Note - the ACCC has advised that import parity pricing considerations from a potential NSW/Victoria LNG import terminal in the future would be subject to a subsequent review.

4. Relevance of international price markers for domestic pricing in the ECGM

This section considers the interplay of different international gas price marker in a global gas market which is increasingly connected. It looks to address the key question of which is the most relevant Reference Price Marker(s) for the netback calculation and when other international price markers might be relevant to price formation in the ECGM.

Section Summary

Relevance of international price markers for domestic gas pricing in the ECGM

- JKM is the most appropriate price marker for the netback calculation, given it is driven by North Asian market dynamics and provides a direct alternative for producers looking to monetise short-term gas volumes. However, it has limited liquidity in terms of traded volume and not typically used to price contract strips >12 months.
- The JKM forward curve is increasing in trade volume depth and may eventually evolve to provide pricing relevance for the ECGM netback price for terms >12 months. However, it may be a number of years before it becomes reliable for ECGM domestic gas sellers/buyers to hedge against, should JKM become a greater feature of domestic term contracts.
- TTF plus shipping differentials display strong correlation to JKM price formation throughout most of the year. TTF also enjoys a liquid gas derivatives market which is second only to Henry Hub in terms of liquidity.
- Henry Hub is based on the market fundamentals of the US market and has limited direct relevance to ECGM domestic gas sellers/buyers..
- Henry Hub “plus” will be a price setting mechanism in the long term given the growing importance of US LNG and its role at the margin to meet demand. However, Henry Hub “plus” remains a poor proxy for short term prices as TTF and shipping differentials with Asia remain the key dynamics for JKM price formation.
- Both Henry Hub “plus” and TTF plus shipping differentials are incorporated into JKM-delivered prices at different times, as is oil.
- Oil indexation might be a more appropriate solution for term contract price discovery, however transparency around indexation levels would be an issue for utilising as ECGM netback pricing reference marker.

4.1. Overview of ECGM Price Formation

Asian LNG markets provide a direct alternative for a Queensland LNG producer to sell gas. Through this, Asian LNG netback prices are a relevant consideration in ECGM price formation.

However, LNG netback price is not the sole factor that influences domestic prices in the ECGM. Prices paid by gas users will also reflect other factors that may be relevant to their circumstances, including:

- cost of gas supply;
- delivery point of gas sales (including any applicable transportation or retailer charges);

- quality of delivered gas supply (e.g. processed/raw gas);
- terms and conditions of gas supply; and
- duration of delivery period and associated risks for a term contract.

4.2. International Gas Marker Influence on ECGM

LNG is sold into Asia under two main pricing mechanisms:

1) Oil indexation, which remains the dominant pricing mechanism for LNG term contracts, i.e. strips of LNG cargoes with contract duration of over 12 months and up to 25 years.

2) Spot LNG prices for uncontracted demand over and above term contracted demand, are negotiated on a bilateral basis and reported daily by price discovery agencies and publications, including Platt's (i.e. Japan Korea Market, JKM) and Argus Media (Average North East Asia Marker, ANEA).

LNG contracts, priced at Henry Hub "plus" (Henry Hub plus a charge for gas procurement, liquefaction fees and shipping), can be sales of LNG directly from US LNG projects and/or portfolios/re-sale. These have gained market share in recent years. Portfolio/resales of Henry Hub "plus" LNG are sold at spot prices.

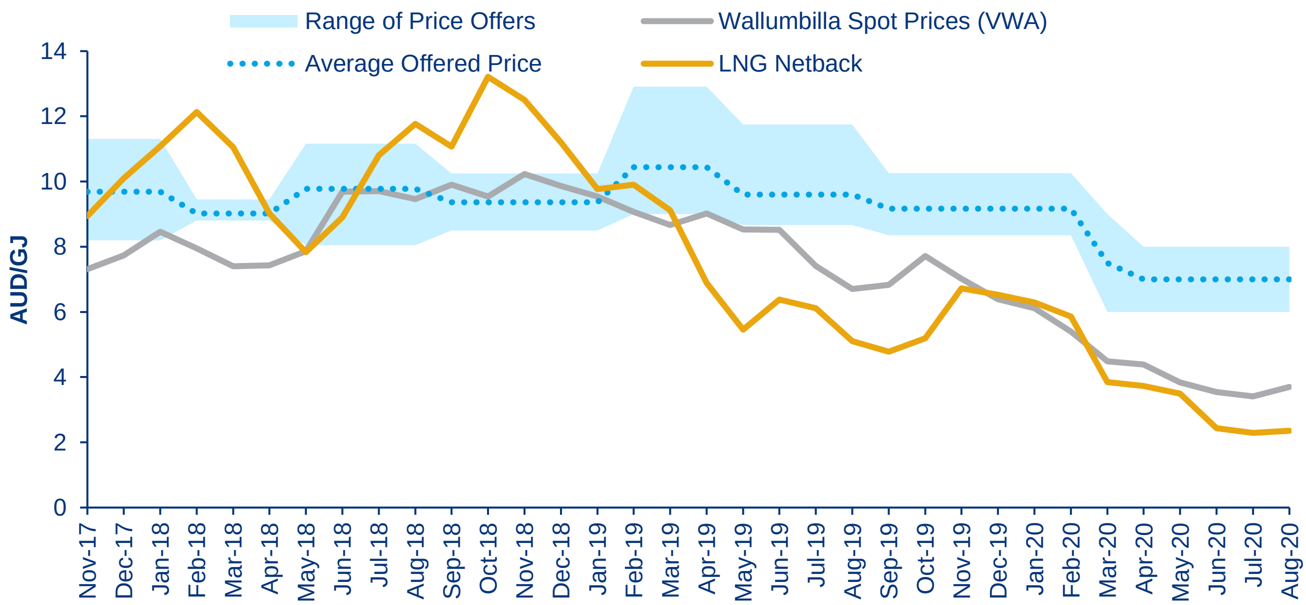
Asian LNG pricing is relevant to the ECGM in that it is the alternative market destination and option for a Queensland producer to sell its gas. International spot gas markers have limited direct influence on ECGM domestic gas contract pricing values, though do have some indirect influence on pricing dynamics. ECGM dynamics in turn have no influence on these international markers investigated below.

4.3. Recent Price Trends in ECGM

There has been a growing divergence between the average ECGM contract offer price and the LNG netback in recent years. This divergence began in early 2019 and has widened through to mid-2020, with LNG netback prices and Wallumbilla spot prices declining more significantly than the average ECGM contract offer prices.

Contract prices offered by gas producers for supply in 2021 declined sharply from a range of A$8–10 per gigajoule in late 2019 to A$6–7 per gigajoule in mid-2020. Prices offered by retailers fell from a range of A$8–14 per gigajoule to $6–8 per gigajoule. By August 2020 there were no offers above A$8/GJ. Spot prices decreased further, falling below A$4/GJ by March 2020.

Figure 18: Comparison of Historical Price Offers, Wallumbilla Spot Prices, and LNG Netback

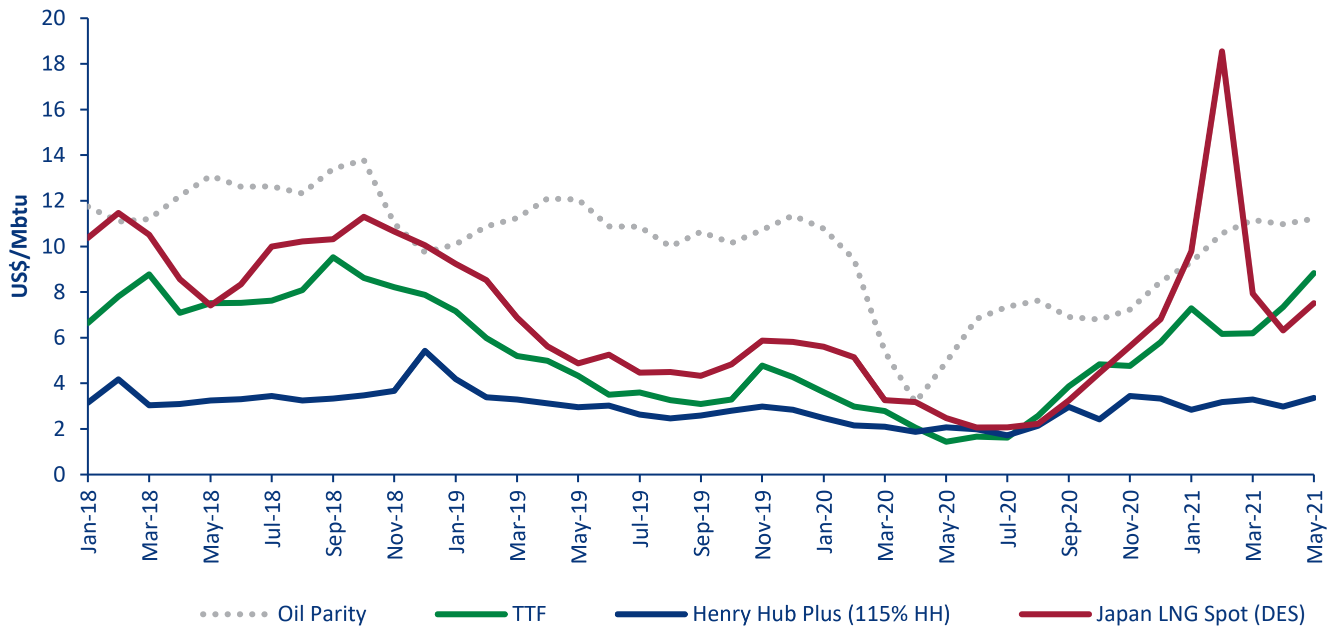


Source: ACCC, Australian Energy Regulator, Wood Mackenzie

There may be numerous reasons why this divergence occurs, though limited supply competition in the market will naturally cause bids and offers to trend above alternative export options. Other explanations for this divergence reflect the differences in duration of these supplies (short versus longer-term), the typical pricing mechanism underpinning domestic contracts (fixed or oil-linked structure) plus buyer and seller expectations of future oil prices at the time of contract negotiation.

4.4. Global Gas Price Formation and Trends

Figure 19: Historical Oil Parity, Henry Hub "Plus", TTF, and Asian LNG Spot Prices (Jan 2018 - May 2021)[1]



Source: Wood Mackenzie, Argus Media. HH+ solely reflects 115% of HH. Other LNG costs (e.g. .LNG capacity charge and freight) are not reflected in this visualization.

There are three key international gas price markers that influence the price of global LNG into different markets. These have increasingly shown convergence through periods of market balance or oversupply, though there are widening seasonal spreads when regional demand (e.g. North Asia) peaks.

JKM Price Formation

JKM is set by the marginal spot cargo into North Asia and therefore is driven by Asia Pacific supply and demand fundamentals. Marginal LNG demand will generally be met by the lowest cost supply option which can generate a profit at the price signal offered. Additional demand will progressively be met by more expensive options, as required to balance the market.

Consequently, JKM is defined by the short-run marginal cost of LNG supply, shipping costs and the economics of alternative fuel use in Asia (e.g. LNG-to-oil switching in the power sector).

But the most important dynamic for the JKM price formation is the "Title Transfer Facility" gas hub in the Netherlands (i.e. TTF). This is because it represents an alternative trading option for global LNG suppliers in the Atlantic and Middle East regions and with its increasing liquidity has now become the "anchor" for global LNG trade.

[1] The Japan LNG Spot/JKM prices used in the analysis are based on historical estimates of Asian LNG spot prices from Argus Media, reported on *a delivered basis (as opposed to traded).* As such, these reported prices may differ from historical spot JKM prices reported by S&P.

Indicatively prices will move up in line with the following stylised steps/influences:

- **Step/Influence 1**. When Asian uncontracted demand is fully met by local (Asia-Pacific) supply, JKM trades at parity to TTF, if not at a small discount. This is because marginal suppliers in the Middle East are “indifferent” to selling LNG either to North Asia or Europe as the shipping distance is broadly similar. This is a common dynamic in the Northern Hemisphere summer months when heating demand in North Asia is low.

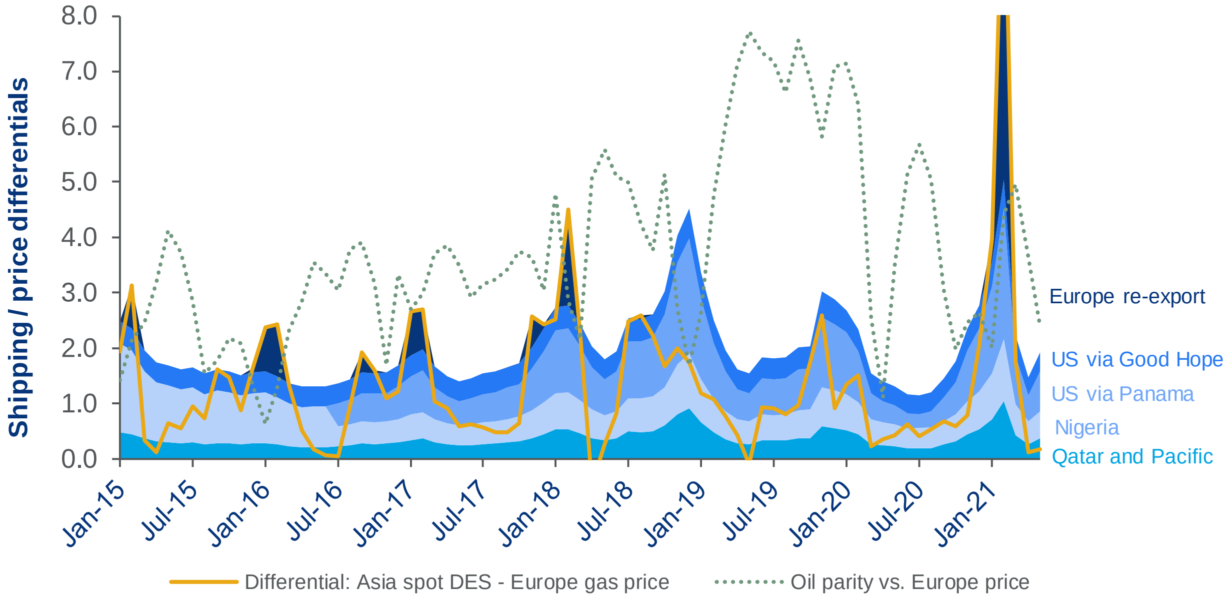
- **Step/Influence 2**. When uncontracted demand in Asia requires LNG supply over and above Asia-Pacific supply, JKM will trade at a premium to TTF. This premium is largely defined by the shipping differentials between North Asia and Europe which will incentivise the marginal Atlantic LNG supplier to send its cargo into Asia when required.

  As the share of US LNG in global trade has increased substantially in recent years, it is often the shipping differential from North Asia and Europe to the US Gulf Coast that sets price differentials between JKM and TTF. As a result, US LNG will be diverted from Europe to Asia. This is a typical dynamic in Northern Hemisphere winter months when heating demand in North Asia is high.

- **Step/Influence 3**. At times of limited LNG supply availability, the JKM premium over TTF increases further to reflect market tightness and the requirement for more LNG in Asia. Despite US LNG being able to provide abundant volume in a flexible manner, it can take between 40 and 60 days for an LNG cargo to do a round trip between the US Gulf Coast and North Asia.

  Consequently, LNG supply from the US might not necessarily be available when required, as it became apparent during the JKM price spikes of the past winter (2020/2021). During these periods of supply shortfall, JKM has historically traded at oil parity, a price level that would signal switching from LNG to oil in dual-fuel power plants in Japan. However, prices might even exceed oil-parity (as happened last winter), as Japanese power prices also spiked due to unseasonably high power demand and limited power supply.

Figure 20: Marginal Supplier to Asia (Simplified)



Source: Wood Mackenzie

Consequently, while TTF is key for JKM price formation, shipping differentials are also increasingly important. Freight charter rates are becoming more volatile in response to these evolving LNG trade patterns. The longer shipping voyages between US Gulf Coast (USGC) and Asia effectively doubles the LNG shipping-mile demand (versus European deliveries) during periods when US LNG is required in Asia. The highly seasonal nature of these trade flows puts pressure on vessel fleet availability, which is expected to continue to be long in North Asian summer and short in winter. These freight constraints are expected to spike day charter rates through North Asian winters, and lead to higher seasonal JKM prices.

Historically, low charter rates have closely been correlated with decreased shipping cost differentials from US Gulf Coast to North Asia versus Europe. Conversely, high charter rates have been linked to surges in shipping differentials.

Figure 21: Historical Charter Day Rates vs. Shipping Differential (USGC to Asia vs. NWE)

Source: Wood Mackenzie

Role of US LNG in JKM price formation

Henry Hub-linked LNG is only the marginal supplier into Asia during periods where the JKM price signals are sufficient to cover its higher costs into Asia (due to its greater shipping distance and feedgas costs). More typically the marginal supplier of LNG into Asia will be priced in relation to the European Title Transfer Facility (TTF) hub price, plus a differential which accounts for the additional shipping cost between Europe and Asia.

While US LNG may be a key determinant for short term JKM price formation, this is really driven by shipping differentials with Europe rather than the Henry Hub price itself.

As long as JKM or TTF are high enough to recover the cash cost of US LNG trade to Asia or Europe, US LNG players can generate a trading profit and consequently will be "price takers". The cash cost includes the cost of Henry Hub, a procurement cost and the shipping cost to market, however it does not include the liquefaction fee as this is considered as "sunk" for the LNG trader itself (i.e. it is paid regardless of whether the LNG cargo is lifted or not).

Consequently, the only time when Henry Hub has a direct influence on JKM (or TTF) is when global LNG prices are below the cash cost of the US LNG trade. This results in US LNG cargoes not being lifted and Henry Hub becoming the "price floor" for global LNG prices, as happened in summer 2020.

4.4.1. Asian gas markers

JKM (Japan Korea Marker) and ANEA (Average North East Asian Marker)

JKM and ANEA (hereinafter JKM) are price assessment markers which reflect the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan (North Asia). These are based on the believed price that sellers offer for physical LNG cargo(s) and the price that buyers are prepared to pay - providing insight into the current price an LNG cargo is understood to be sold and purchased at.

JKM is the most commonly used, North Asia-related LNG price marker, with derivatives and associated forward curves which are technically tradable 5-7 years out (albeit with extremely low liquidity beyond 12 months). The North Asia LNG market is the most relevant to Queensland LNG producers for potential additional “surplus” LNG sales.

The growing importance of the Asian spot LNG market has prompted international exchange firms (i.e. ICE, CMI) to launch daily traded options (i.e. JKM swaps) based on the JKM daily assessment. Liquidity of these options have increased substantially over the past 2 years, but churn rates remain low compared to liquid energy commodities (e.g. Henry Hub or TTF).

Relevance of JKM as an ECGM price marker:

JKM’s relevance as the Reference Price Marker for the ECGM reflects:

- JKM represents the best alternative option and effective price a Queensland LNG producer would expect to receive for incremental LNG (excess gas) sold on a spot basis.
- JKM has started to be referenced in some ECGM domestic gas contracts, including the Origin Energy-APLNG 4-year gas sale agreement for up to 91 PJ of gas beginning 2022 (APLNG announcement 5 May 2021).[2] Other JKM-linked deals are understood to exist in the ECGM.

Limitations of JKM influence as an ECGM price marker:

JKM netback pricing provides limited insight to domestic term gas price contracts, which affects its ability to provide transparency to ECGM price formation. ECGM gas buyers require firm supply under term contracts (often 2+ years) while the JKM as a spot market price (on a netback basis to the ECGM), may be less relevant to the domestic contract gas price formation.

There has been very few, direct JKM-linked pricing contracts in the ECGM. Some domestic gas contracts index JKM for all or a portion of its pricing structure, but these have unique counterparty conditions which mitigate risks. Most domestic gas buyers would be concerned about the price volatility risk of JKM-linked pricing as well as the exchange rate variability. JKM derivative limitations mean that even where it exists as a relevant marker for a ECGM trade, it cannot be appropriately hedged to manage price exposure

JKM is a third-party price assessment carried out by market survey by a price reporting agency. While it has transparent methodologies and controls in place to ensure these reasonably represent market prices, limited trade liquidity and transparency over the number of actual trades versus assumed prices on a daily basis, affect confidence levels in its appropriateness as a price marker against which long-term contracts can be indexed.

JKM’s limited liquidity also exposes it to risks around outlier trades and market manipulation through the bidding process. An example of this was seen in winter 2020/2021 where spot prices were driven to unprecedented levels through a small number of bids. These conditions did not necessarily reflect the actual

[2] However, as Origin Energy has an equity position in the APLNG project and therefore, in part has a natural hedge to JKM price risk (being a buyer and seller). Origin Energy can also manage the potential seasonal volatility in JKM pricing as it has higher gas demand requirements for it southern market residential customers (winter) when JKM prices tend to be lower and will take lower JKM-linked volumes in the Australia summer when domestic gas demand is lower and JKM prices can be more volatile.

spot market prices a Queensland LNG exporter would receive and therefore the ACCC might like to consider mechanisms which adjust for such extraordinary events.

The JKM forward curve does not have much liquidity beyond 3-12 month period and credibility beyond 24 months to provide insight into longer-term LNG netback price expectations. However, the JKM forward market is improving in terms of volume traded and may become more relevant over time.

4.4.2. European gas markers (TTF)

Europe has extensive gas market infrastructure (over 100 Bcm of storage capacity and multiple LNG import terminals) which together with supply and demand flexibility offered through the connectivity of its extensive pipeline network and fuel-switching potential create the conditions for a fully functioning regional gas hub (e.g. gas supply and demand liquidity).

European gas prices have a floor set by carbon prices and coal-to-gas switching dynamics and beyond that are influenced by the volume of imported LNG and Russian pipeline gas. Europe has evolved into the market sink and balancer for global LNG (market of last resort) both for physical and paper trade due to this supply and demand flexibility. This enables it to take large volumes of additional gas (and LNG) during periods of surplus global supply.

Spot LNG imports into Europe are priced at TTF minus the cost of regasification, which allows the regasification tariff to be recouped and the gas to compete in the European gas market. This effectively sets a floor for global LNG prices.

TTF (Title Transfer Facility, Dutch natural gas pricing point)

TTF is a Netherlands gas hub index. Its relevance to global gas pricing is that it is most often the market of last resort for surplus global LNG supply and the usual destination for flexible US LNG spot cargos, when pricing signals in Asia do not support inter-basin arbitrage.

TTF is nevertheless set by the supply/demand dynamics of the Europe gas market and market dynamics in Europe are different to those in North Asia (for example political influence in gas pipelines flows, environmental policy direction, different economic growth paths). Its gas supply is a mix of LNG imported supply, indigenous gas production and long-distance pipeline supply.

Relevance of TTF as an ECGM price marker:

JKM prices are increasingly anchored to European pricing dynamics (eg TTF plus the shipping differential) with this correlation visible during most of the year. Therefore there is potential relevance of TTF dynamics on Queensland LNG spot decisions at times. TTF is also a deeply traded and transparent index, with a credible futures market which could be an option for an ECGM gas buyer looking to contract and hedge some price risk exposure.

In the Northern Hemisphere winter, JKM prices tend to disconnect from TTF and are driven by Asian market dynamics which can see US LNG (Henry Hub “plus”) set the marginal price. With expected seasonal JKM spikes and Queensland LNG’s shipping advantage to North Asia, incremental spot sales would be more likely to target high-value seasonal opportunities, particularly if ADGSM restrictions and gas reserves coverage issues became a more prominent part of incremental export decisions.

Limitations of TTF influence as an ECGM price marker:

TTF itself is ultimately driven by the supply/dynamics of the Europe gas market and therefore has limited direct relevance to Queensland LNG exporters. The European market is not the market a Queensland LNG producer would normally sell into.

TTF's influence on JKM also needs to take into consideration freight costs, which are a key component of the shipping differential between TTF and JKM and can be extremely volatile. Furthermore TTF plus the shipping differential does not always link back to JKM pricing.

4.4.3. North American gas markers

Henry Hub (US natural gas pricing point)

Henry Hub is a North American gas pricing point with its settlement prices driven by actual and expected North American gas supply and demand dynamics. It acts as the virtual delivery point for both physical volumes and for gas futures on the New York Mercantile Exchange (NYMEX). Since the first exports of US LNG in 2016, it has been used as a benchmark for both North American gas prices and LNG exports from the US.

Henry Hub's key relevance and advantage as an international gas pricing marker lies in its considerable trading liquidity and the depth of its futures market. Henry Hub itself has no direct relevance to the Australian domestic gas market, though Henry Hub converted into LNG may have indirect relevance insofar as it is the marginal cargo sold on the spot market, or it sets the marginal cost of new long-term LNG supply.

However, crucially US LNG contracts are sold on Henry Hub "plus" basis. This "plus" refers to Henry Hub generally being multiplied by 115% (which accounts for the seller's gas procurement and liquefaction fees plus shipping) and an additional tolling or capacity charge that is contractually agreed between buyer and seller. While this tolling charge is generally considered sunk and not relevant to short-term decisions around spot US LNG cargoes, reference to any exported Henry Hub volumes must include this "plus" element.

US LNG is one of the LNG supply sources competing to supply into Asia but it is not the alternative LNG price that an Australian LNG supplier would seek or be able to sell at. Therefore, US LNG may influence the cost of supply (including shipping) into the Asian market at times, but as it competes with whichever other LNG supply sources is at the margin. This dynamic will likely be captured in Asian spot price assessments such as JKM.

Relevance of Henry Hub "plus" as an ECGM gas marker:

US LNG's 'infrastructure type' flexible supply model means it is also the most responsive to short-term LNG price signals and through this it is often seen as the marginal supplier of LNG, being able to respond to both Asian and European demand and pricing signals. However, its influence on TTF and JKM pricing throughout the course of a year remains limited because it is not the only supply source influencing these markets.

Henry Hub-linked LNG price may be more relevant in the future if an Australian LNG import terminal were to contract LNG supply on a Henry Hub "plus" basis. Henry Hub "plus" will also be influential in longer-term price setting in North Asia in so far as the cost structures of US LNG will set the marginal cost of new LNG project developments for sale into North Asia.

Limitations of Henry Hub "plus" as an ECGM price marker:

Henry Hub "plus" remains a poor proxy for short term prices in Asia as TTF and shipping differentials with Asia remain the key dynamics for JKM price formation. Henry Hub "plus" is only a component of the delivered cost of US LNG into Asia. The extent of US LNG's influence on Asian LNG prices is dependent on market conditions (i.e. when the Asian market imbalance requires the marginal cargo to be met by US LNG).

Henry Hub is the major gas hub index in the US and prices are driven by its own domestic supply and demand fundamentals. Feedgas demand for US LNG exports makes up only a small (10%) percentage of the overall physical US market and therefore international gas market dynamics have limited influence on its price formation.

4.4.4. Non-gas markers (oil)

Oil-linked LNG

While the JKM price marker is representative of the spot LNG deal space in Asia, oil indexation remains the dominant pricing mechanism for term LNG contracts, i.e. strips of cargoes with durations of between 12 months and up to 25 years.

In recent years, oil-indexed LNG contracts have been increasingly priced against Brent, though close to 50% of legacy LNG contracts globally are indexed to the Japan Customs-Cleared Crude (JCC). JCC is the weighted average price of a mix of crude oils imported by Japan, mostly comprised of sour Dubai and Oman crudes and 10% Brent.

Historically, gas-based indexations (e.g. Henry Hub or TTF-linked LNG) have been more prevalent in term contracts when oil prices are higher (e.g. 2013-14 and 2018-19). Though over the past 10 years, most new Asian LNG term contracts (around ~70%) have been indexed to oil compared to other indices, including Hybrid deals (part gas, part oil-linked).

Indexation to international gas and oil price markers is attributed to the lack of a physical Asian gas hub pricing mechanism that is sufficiently transparent, liquid, market-based, and accepted by both buyers and sellers for financing or hedging long-term LNG deals.

While there is a global trend towards more short-term, spot and Henry Hub/TTF/Hybrid pricing, this remains less pronounced among Asian LNG buyers who still predominantly look to oil indexation due to its deep, transparent and liquid market and the availability of Brent Futures to hedge positions against.

Providing an oil indexation proxy price to the ECGM might be a more appropriate solution for the ACCC to consider in respect of what influences medium or long-term domestic gas prices. However, transparency around indexation level relies on market intelligence and therefore remains an issue.

Developing an oil-linked price formula proxy for the ECGM would likely provide more transparency over gas sales decisions for contract terms over 12 months. This is because:

- It is relevant to North Asia LNG contract prices;
- It is relevant to the mechanism used to set a number of medium-term (2-10 years) ECGM domestic contracts (either directly as oil-linked GSAs, or oil-linked influences in fixed price contracts, which mirrors the preference ECGM gas buyers have for term contracts); and
- It is relevant to domestic gas buyers as it provides the LNG alternative for a Queensland LNG producer to sell gas on a term basis.

While bilateral LNG contracts are confidential in nature, Wood Mackenzie and other market commentators or LNG consultants do develop and publish assumptions around what the prevalent LNG oil-indexation formula may be in at any given point in time. This is derived from market intelligence of contracts signed (eg market participant discussions, analysis and other market assumptions).

Oil-linked netback prices would also need to be converted at the current oil price or forward oil-price curve to provide an indicative fixed domestic gas price. Brent forward curves or other oil price forecasts are widely available for this purpose.

Relevance of oil-indexation as an ECGM price marker:

Oil-linked LNG contracts, particularly in the medium and long-term (>2 years), have ongoing relevance in the Pacific Basin LNG market while oil-linked pricing also has relevance to the ECGM, though both netback price as many existing contracts (both LNG and some domestic gas contracts) have oil-linked formulae. Many of these contracts are related to gas sold to LNG producers – with the oil-linkage providing a back-to back hedge against price movement risk with the LNG producers who sell their contracted LNG on an oil-linked basis. Domestic gas contract examples include (not exhaustive):

- Santos-GLNG "Horizon" gas supply contract
- Meridian JV – GLNG gas supply contract
- Senex – GLNG Roma North gas supply contract
- Arrow Energy – QCLNG Surat Basin raw gas supply contract

Limitations of oil-indexation as an ECGM price marker:

LNG contracts are confidential to the Buyer and Seller and there is no publicly listed record of actual or current LNG contracts or price formulae. As these are traded bilaterally and not on an index, transparency to deriving the appropriate oil-linkage would be issue, as would acceptance of their accurate representation of ECGM-relevant contract terms (e.g. levels at which a Queensland LNG exporter would sign deals). For example, suppliers may sign LNG deals at certain levels for strategic or other bilateral influence reasons (e.g. Qatari government-to-government deals). Furthermore, there are multiple additional parameters to the oil-linkage that may have value within an LNG contract (flexibility in delivery terms, volumes, seasonality, constant etc.).

4.5. Relationship between Asian LNG spot and global price markers

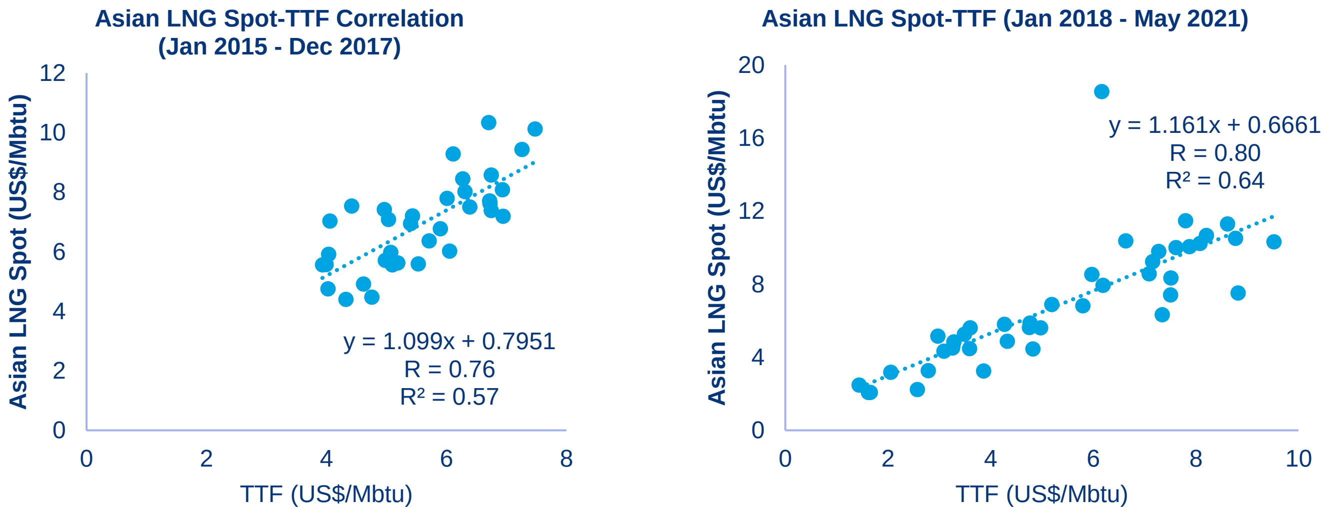
4.5.1. *Asian LNG – TTF*

Historically, Asian LNG spot prices were de-linked from European hub prices due to a lack of overall liquidity in the global LNG spot market. However, supply liquidity has increased as more flexible LNG production (particularly from Qatar and the US) have become a greater feature of the market.

European and Asian gas-linkage has continued to strengthen over time, as the role of the Dutch TTF as a global gas benchmark gains further traction. This represents a considerable shift in import dynamics. Asia had accounted for around 84% of LNG supply from the past five years, whereas Europe itself has soaked up around 68% of incremental supply in the year to date. With Europe now a huge offtake region for LNG, gas markets globally have become increasingly linked to Europe's most liquid gas hubs.

The increased output from Qatar has likely supported this linkage, largely due to its low LNG production costs and its geographic location between European and Asian LNG markets. In practice, Qatar's ability to arbitrage between Europe and Asia, on the basis of netbacks to either region, means that Asian LNG spot prices may be influenced by gas and LNG prices in Europe. Moreover, prices at the TTF gas hub are considered to act as a floor price for Asian LNG spot prices.

Figure 22: Historical Correlation between Asian LNG Spot and TTF Prices[3]

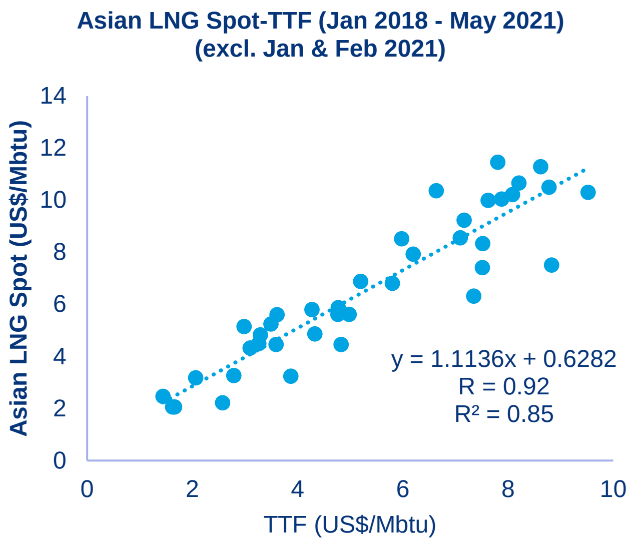


Source: Wood Mackenzie

Exclusion of the divergence in prices witnessed in January and February of 2021 would further improve the R^2 of JKM-TTF from 64% to 85% for the Jan 2018 – May 2021 period.

[3] Because WM's analysis relies on JKM prices estimated based on historical Asian LNG spot prices from Argus Media (reported on *a delivered basis (as opposed to traded)), correlation coefficients may differ* if historical spot JKM prices reported by S&P are used instead

Figure 23: Historical Correlation between Asian LNG Spot and TTF (excl. Jan-Feb 2021)



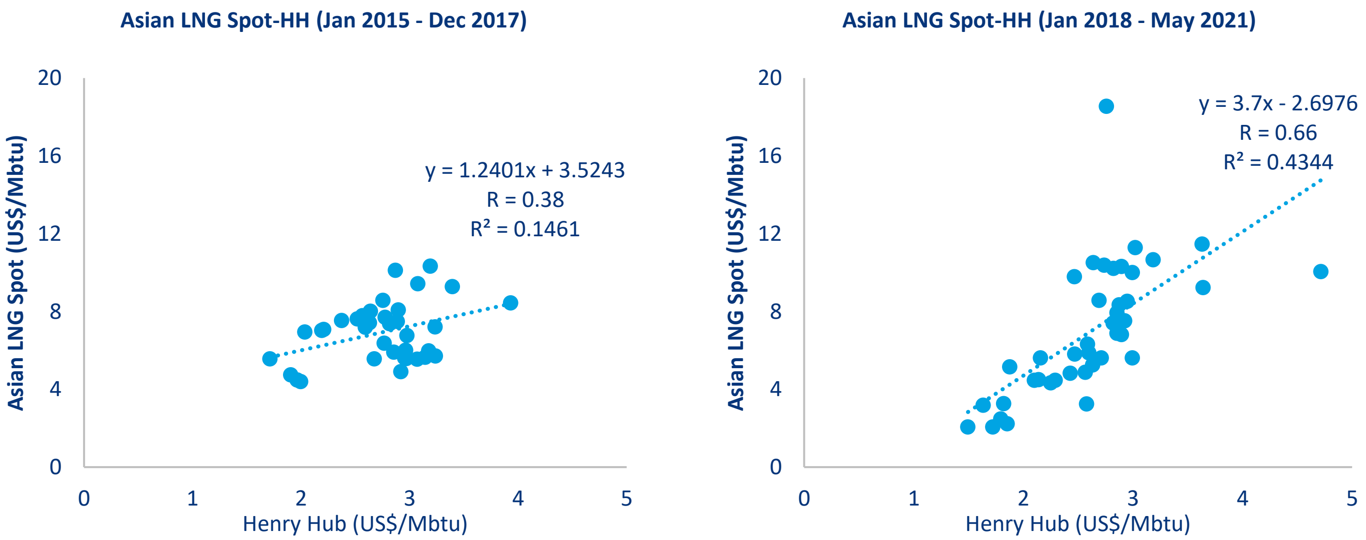
Source: Wood Mackenzie

This shows the pricing influence between the Asian and European regions, with the differential tied to freight costs and driven by regional factors (such as storage, weather, seasonality) that contribute to price volatility. Freight costs and vessel availability also contribute to price volatility in certain market conditions (e.g. North Asian winter).

4.5.2. *Asian LNG – Henry Hub*

The linkage between Asian spot and Henry Hub has likewise increased since 2015, with R^2 increasing from 15% in 2015-2017 to 43% since 2018. This change is attributable to the increased volumes of US LNG in the global market, which *at times* influences and sets Asian spot prices. This is again indicative of a global gas market which has grown in connectivity, as Henry Hub, TTF, and Asian spot price have seen not just strong correlation but convergence since 2019 (although this convergence has been proven to be weak during volatile market periods).

Figure 24: Historical Correlation between JKM and Henry Hub Prices



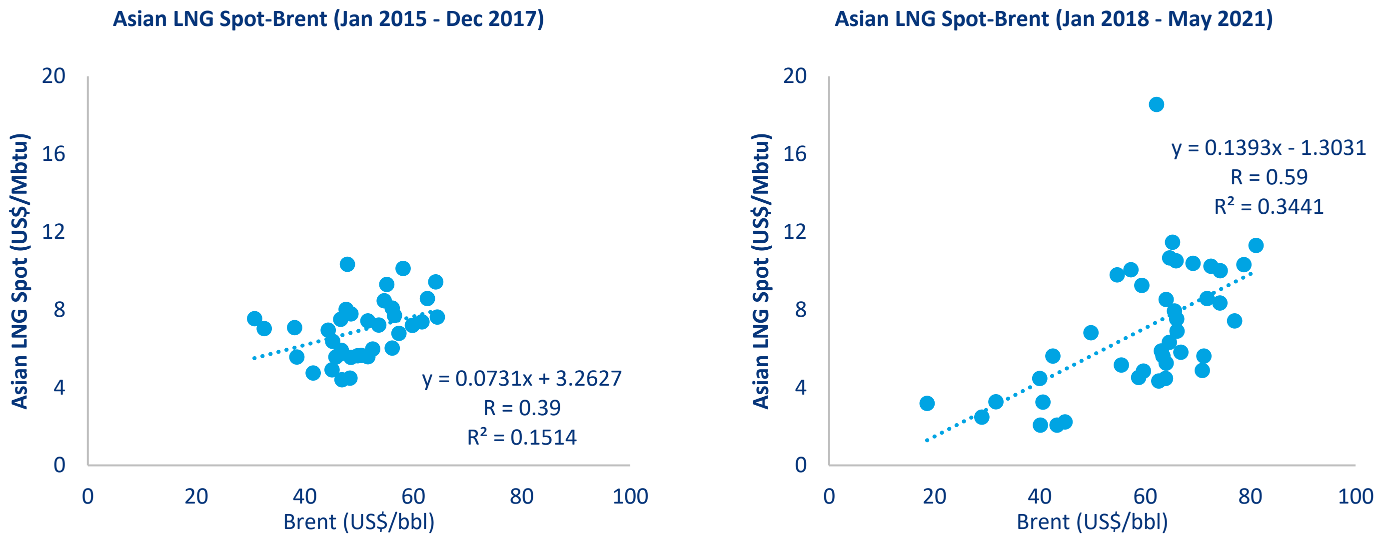
Source: Wood Mackenzie

4.5.3. *Asian LNG – Brent*

Similarly, the correlation between Asian LNG and Brent has increased slightly over the time period. Oil prices will likely continue to have an impact on gas prices, primarily due oil-linked contracted supply.

Historically Asian spot prices have tracked LNG long-term contracts, the majority of which are linked to oil prices. However, Asian spot gas dynamics have at times been disconnected from oil-indexed price trends, reflecting regional LNG supply and demand conditions. As such, Asian spot price movements will remain dependent on factors impacting international oil markets as well as regional/APAC gas market dynamics.

Figure 25: Historical Correlation between JKM and Brent Prices



Source: Wood Mackenzie

4.6. ECGM buyers contracting requirements and relevance of LNG netback price markers

As outlined in Section 3.1.5, ECGM domestic gas buyers have a requirement for term contracts for gas supply ranging from 2 years up to 20 years. This is to provide certainty of supply for their operations. There is a mismatch between the requirements of ECGM gas buyers and the LNG netback price marker in terms of the pricing signal it provides - e.g. longer-term pricing versus shorter-term pricing.

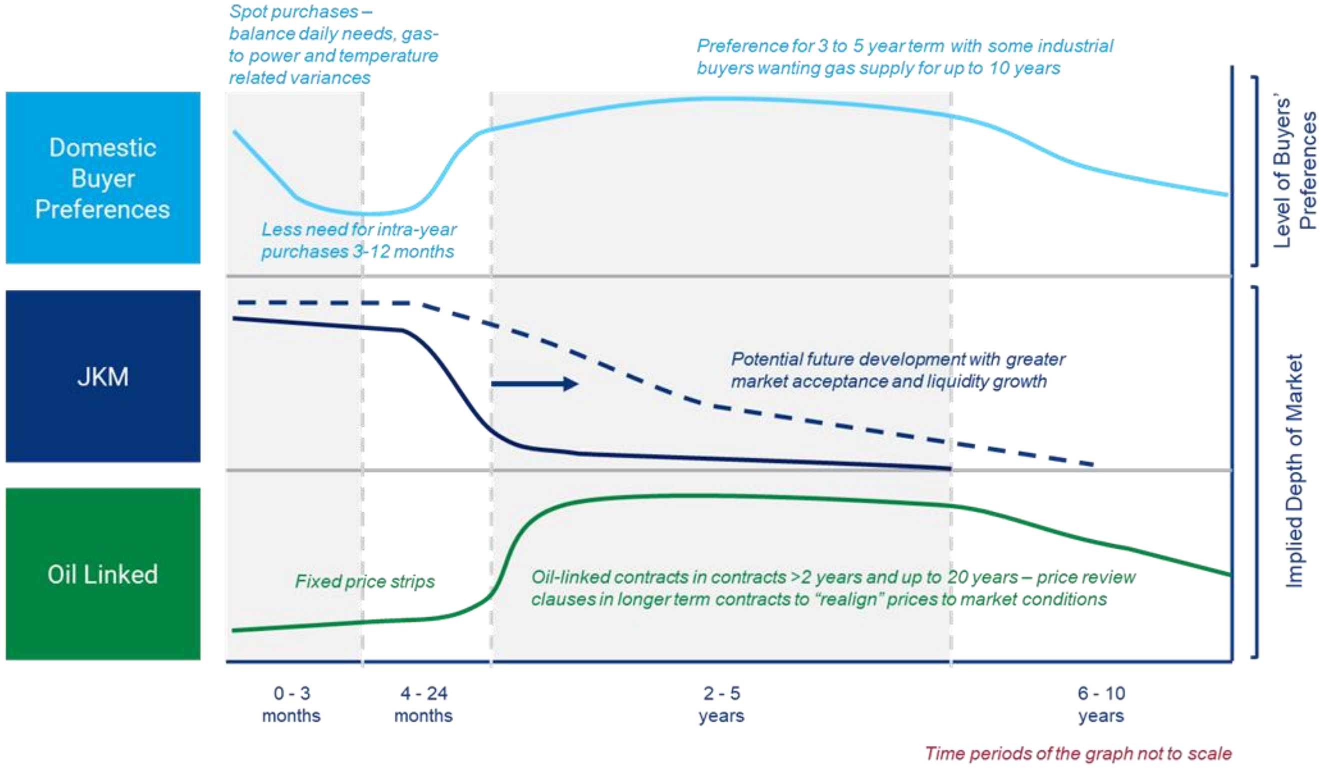
As illustrated in Figure 26 domestic gas buyers generally do not require material volumes of short-term or spot gas supply. ECGM buyers use spot trading to manage imbalances in their supply/demand needs and in response to the high demand variability that can occur in the power market (gas-fired generation).

The LNG netback price is based on the opportunity cost for the LNG exporters. The LNG netback price based on JKM reflects a shorter-term price marker (<24 months). There is little to no depth in the JKM futures market beyond 24 months and therefore longer-term pricing signals are less reliable. The JKM marker is evolving and is expected to have greater depth in longer term trading over time (although it is unclear how long this growth in liquidity and trading depth will occur).

Oil-linked pricing in LNG contracts is used for longer-term LNG contracts (ranging 12 months up to 25 years) – Price Review clauses (~ every 5 years) can result in adjustment to the oil-linkage formula. Oil-linked contracts enable the parties to hedge oil price variability.

Whilst the JKM LNG netback price provides a relevant price marker to the ECGM in the short term (up to 24 months), an oil-linked LNG netback price marker may provide ECGM gas buyers with a more comparative price market for their term contracts. As the JKM market develops over time, the relevance of the oil-linked markers to the ECGM may diminish.

Figure 26: Indicative Domestic Buyer Preference for Contracting Term vs. Netback Price Markers



Source: Wood Mackenzie

4.7. Conclusions/observations about relevant price marker

The guiding principles for determining the relevance of international price markers in respect of the ACCC netback calculation should include:

- Sufficient relevance to gas sales/purchases in ECGM;
- Be consistent with the overall methodological approach for estimating other elements of the netback (e.g. opportunity cost approach);
- Provide a representative view of market conditions at the time of trade/prompt outlook for trade, which guides cargo lifting/production decisions (and the lead time for these);
- Where possible have relevant longer-dated price forward curves which enable market participants to trade and hedge positions over a period more aligned with domestic gas contracting activity;
- Have accessible and publishable datasets and with high confidence and reliance levels, or broadly indicative of future costs and prices; and
- Be resilient as an approach to expected future market conditions and/or emerging trends.

On this basis, JKM provides the most relevant marker price for a Queensland LNG exporter as it is the most representative of the price achievable for a marginal cargo to balance the North Asian market. TTF and HH have only indirect relevance to the ECGM though their impact on JKM.

All international price markers have grown in influence with respect to North Asian prices in recent years, a fact that can be seen in the regression analysis. This is reflective of a global gas market that has become more connected as a whole, and shouldn't indicate the importance of one international price marker over another. Both HH and TTF will have influence and correlate with Asian LNG price setting *at times*, but both of these influences will be captured in JKM *at all times*.

ECGM gas buyers require longer duration (“term”) supply - currently JKM netback marker has less relevance for term contracts in the ECGM. This might be addressed by ACCC considering the provision of an oil-linked slope assumption indicative of new LNG strips into North Asia until such time as JKM becomes a more accepted long-term price marker.

In the future, if as expected JKM is increasingly used in term LNG contracts into North Asia, JKM will increase its relevance to domestic gas term contracts. The pace and scale of this change is uncertain though the ACCC might like to assess progress of this in a future review of the LNG Netback Series in 2-3 years.

5. Freight Cost Forecasting Approach

Freight costs are an important element of the netback calculation, featuring both as a key influence on JKM price formation but also as a standalone cost category in the transport netback from Tokyo to Gladstone. This section reviews the current approach to charter rate forecasting, and the potential to extend out these forecasts to align with the longer-term netback price transparency aims of the current ACCC review.

Section Summary

- LNG vessels are a significant capital investment serving a niche purpose. Most are built with long-term charter contracts in place and spot/short term chartering is a small percentage of the overall LNG chartering market.
- As spot and short-term LNG trade becomes a greater feature of the LNG market, short-term chartering may also grow directionally, though unlikely to track market share percentages.
- The charter cost assessments/forwards developed by Price Reporting Agencies and Brokers suffer from poor market liquidity beyond the prompt (>12 Months).
- The depth and accuracy of these M+12 assessments may improve though additional prompt liquidity, but forecasts face accuracy challenges the further out these go.
- Exchange derivatives and forward curves are a potential source of more actively traded data, but will require investigation over liquidity and depth of market, plus how these might evolve.
- Freight costs (and potential fluctuations over the longer term) represent small proportion of the overall netback calculation value.
- Freight spikes beyond the typical range are often due to unforeseen circumstances and essentially unforecastable.
- Long-term freight forecasting is typically developed using assumptions around new-build vessel costs and payback periods – LNG market participants, brokers and consultants use their own proprietary models and assumptions to develop a house view.
- Many of these long-term views are not freely available* in public domain, and hence the quality and robustness of their forecasts is not measurable. Consensus views could be obtained through discussions with brokers and other market participants.
- Long-term freight assessments may be misaligned with opportunity cost methodology (as new-build or LT chartered). LNG players typically take the view that the opportunity cost is equal to the foregone revenue of chartering out the vessel at current spot rates

Relevance of Freight Costs to the Netback Calculation

As described in Section 4, shipping differentials make up a significant component of JKM price formation during much of the year. Freight charter rates therefore have a dual influence on the netback calculation, firstly as an increasingly important component of JKM pricing, but also as a pure netback cost in the calculation.

In terms of materiality, freight costs typically comprise a relatively small part of the overall delivered LNG cost from Gladstone (eg around 5-10%). However, both temporary and structural dynamics can significantly affect the supply and demand position of the global LNG shipping fleet, and result in considerable short-term volatility in spot charter rates. For example, recent monthly-averaged short-term charter rates fluctuated from a high of US$172,000/day (Jan-21) to US$27,000/day (Mar-21) with daily charter rates showing even greater variation.

LNG Freight cost fundamentals

LNG freight costs predominantly consist of vessel charter costs (which may be considered a sunk or cash cost depending on whether there is an existing term charter contract or not).

The charter rate is the highest proportion of LNG freight costs and varies depending on the class and size of vessel. Larger carriers have both higher operating (e.g. canal and port fees) and capital costs but benefit from economies of scale. Newer vessel types (eg MEGI and X-DF) may enjoy lower natural boil-off rates and lower fuel oil consumption compared to other carriers due to more efficient engine technology.

The second largest component will be fuel costs, either LNG 'boil off', which is gas utilised in propulsion and therefore unsaleable, or fuel oil. While these are influenced by commodity price supply, demand and pricing dynamics, these are a much smaller component of overall freight costs and therefore subject to less variance and volatility.

Boil-off rates differ depending on technology of the vessel, the volume of LNG carried, and the stage of voyage (laden, ballast or when the tanker is in port). Several vessels, especially newer ones, have reliquefication capabilities which minimise the amount of boil-off produced.

The return leg of the shipping voyage includes a cost incurred for 'losses' such as retaining sufficient LNG in the 'heel' to ensure the vessel membrane remains at the operational temperatures necessary for the next loading, as well as to be used for fuel (after accounting for 'boil off' gas).

Other costs may include; port charges at the source or destination port and tolls for using shipping passages such as the Suez and Panama Canals, if these routes are utilised. Brokerage commissions, insurance and other ancillary charges make up the remainder of freight costs, but are largely insignificant in terms of overall costs.

Different Price Reporting Agencies may apply different assumptions and combinations of these cost categories described above in their published assessments.

Freight cost forecasting

The ACCC currently calculates its forward LNG netback prices using forward LNG freight costs assessed by Argus Media, which are available for up to a 24-month period. While there may be alternative, credible forward-looking assessments, all of these will likely face similar challenges in terms of sufficient churn in volume of bid/offers, and in transparency of assumptions.

Figure 27: Freight Component of Netback (Historical*)

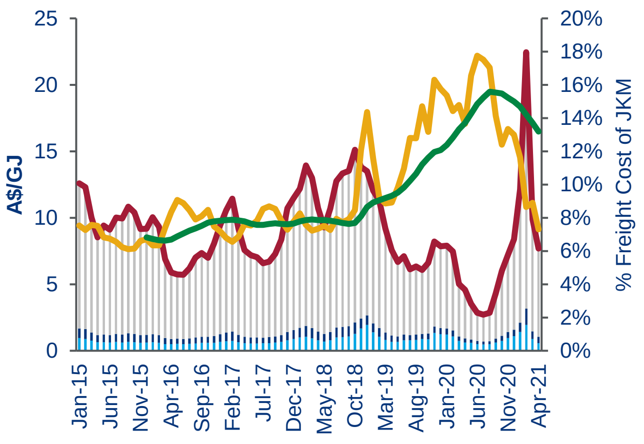
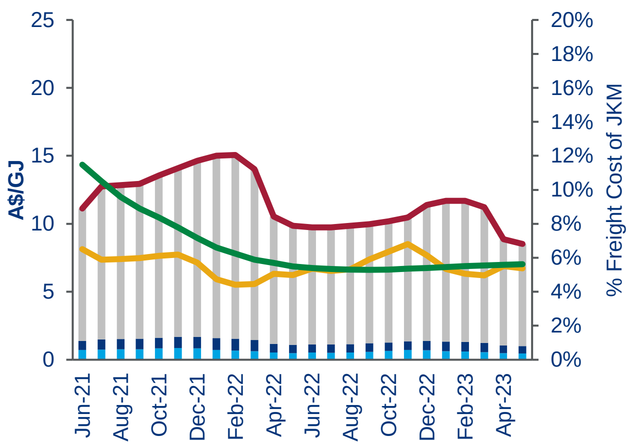


Figure 28: Freight Component of Netback (Forward)**



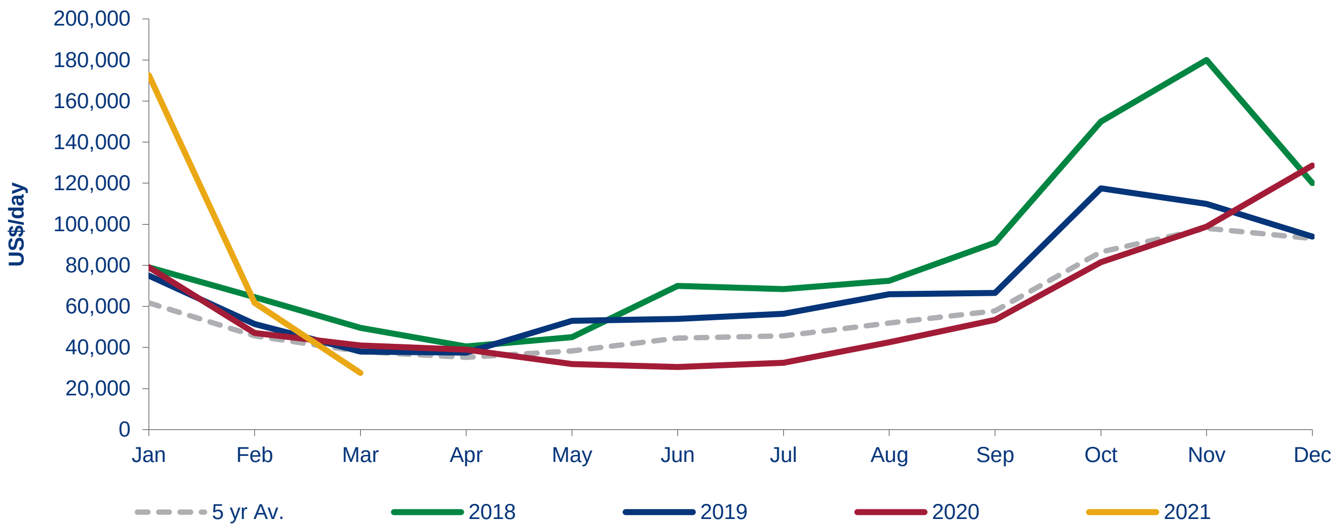
*Note(s): * Based on Argus Media and WM's historical data (Asia LNG DES price, freight rates)*
*** Based on S&P Platts' forward data for JKM and freight rates (obtained via ACCC Netback Series); the 12-month SMAs for June 2021 – April 2022 rely on a combination of both historical data based on Argus Media & WM as well as Platt's forward curves*
Source: Wood Mackenzie

Charter rates can vary significantly depending on market supply and demand dynamics, due to both structural and temporary factors. This makes them especially challenging to forecast accurately beyond the 1-12 month prompt or short-term period, as visibility over vessel bids and offers falls significantly. Seasonal patterns are an important factor (particularly during the Northern Hemisphere winter) but other temporary dynamics can significantly affect rates.

Key factors that can affect carrier demand and availability, and therefore short-term charter rates, are:

- Arbitrage opportunities between the Pacific and Atlantic basins
- An increase or decrease in size of the available carrier fleet due to new deliveries or decommissioning of old vessels
- Companies trade strategies including carriers being utilised as floating storage
- Blockages and delays at either the Suez and/or Panama canals
- Variation in demand for LNG e.g. the cyclical nature of short-term charter rates is primarily driven by variations in seasonal gas demand in European and Asian markets
- Sanctions on ship owners

Figure 29: Global Spot/Short-term Charter Rates



Source: Wood Mackenzie

Long-term freight forecasting

Long-term freight cost forecasting (e.g. for periods >2 years) requires a future view of LNG market conditions, vessel fleet capacity and new-build costs (including *inter alia* yard availability and steel costs). Though as with all forecasts, actual market dynamics may take a different path and cause alternative outcomes. Indeed long-term forecasts are naturally more susceptible to error margins than those for making decisions in the nearer term, as these are less influenced by currently observable dynamics.

Freight charter rates displayed little seasonality prior to the advent of US LNG exports from 2016. The increased shipping-mile demand from flexible US LNG as and when it is required to meet marginal Asian demand changed this. As Asian LNG demand grows, increasing amount of Atlantic LNG is expected to be required to meet demand particularly in winters, resulting in increasing requirements for shipping and therefore higher charter costs.

The shipping market is expected to be long in Northern Hemisphere summers and short in Northern Hemisphere winters. While seasonality is expected to exhibit this recurring pattern, it remains heavily linked to the specific market conditions for a given year.

Longer-term charters are used by shippers to ensure more controllable freight outcomes. These offer the opportunity for term charters to be 'locked in' for the duration of the contract, at an agreed rate at a particular point in time (eg year + X), and insulating the charterer from short-term volatility.

A view on future vessel availability will necessarily underpin all longer-term forecasts, though the further out the forecast goes, the more potential for the market to respond to pricing signals and redress the balance by incentivising new-build vessels in the intervening period. On this basis, it might be expected that longer-term forecasts can be generated through assessing expectations over new-build vessel costs.

5.1. Review of freight cost assessments, methodology, and limitations

Independent Price Reporting Agencies (PRAs) publications exist to provide transparency to charter costs. Assessments are made by assimilating data received from multiple sources to assess and report market values at a particular point in time. Some of these can be editorial in nature and have the aim of turning qualitative information into quantitative values where data on actual trades is unavailable.

In terms of forward freight costs, Argus Media publishes a forecast for a given future month. This forward freight cost is subtracted from the ICE JKM futures quote for the corresponding month to give a forward FOB price at Gladstone. These are more subjective, as to Wood Mackenzie's understanding, there is limited liquidity in the year ahead vessel chartering market, and this approach assumes that Argus Media (as the sole PRA that provides this data) is able to capture the market sentiment accordingly.

There is no well-established LNG charter rate futures market directly linked to settlement prices. The Baltic Exchange has been developing a derivatives product but there is little information on the liquidity of this to date. This may be an area warranting further investigation.

Much like price reporting agencies, freight cost assessments (carried out either by price reporting agencies, brokers or market consultants) may be expected to increase in accuracy and confidence levels as the number of actual trades reported increases.

However, spot and short term LNG charter assessments have two fundamental challenges facing them.

1) Vessels available for spot and short-term (<24 months) charter trades reflect a small proportion of the overall market,
2) The remaining contestable vessel market may not have sufficient actual trades in any particular month to provide confidence in the level of assessment, and
3) Transparency of data (as these are typically sourced from ship broker market intelligence)

On the first of these points only 7% of global annual LNG vessel fleet in 2018 were available for spot and short-term charters, with the remainder tied up on long-term charter. Therefore, the contestable vessel market is limited to new builds on order and not tied to a particular projects/charterer, or uncontracted vessels.

It might be expected that these spot and short-term trades form the predominant basis on which freight cost assessment are made given greater availability and churn of vessels which are not 'locked out' of contestable market. Given the relatively small pot of available vessels remaining, we might expect the volume of actual trades to be low in any particular month, providing less confidence in reflecting actual market conditions.

A third consideration of the shipping market is that freight costs are inextricably linked to global LNG pricing dynamics, shipping availability and route availability (e.g. Panama Canal passage).

Spot cargo trade continues to grow, though it is difficult to determine how much of this is shipped under term charter versus spot charter. Research carried out by Clarksons (2016) and other parties highlight that between 70-90% of all vessels are contracted based on long-term charters.

The Queensland LNG players mostly have dedicated shipping fleets under long-term charter. Given these incur take-or-pay (fixed) charter costs irrespective of utilisation there is an economic argument that the fixed element of costs should be considered sunk in line with the treatment of other netback categories (plant, pipeline) in the existing methodology. The net impact of this would be to eliminate a significant portion of freight cost category from the netback calculation and increase the Gladstone FOB netback price.

Nevertheless, LNG players typically adopt an opportunity cost approach in respect of vessel utilisation even where vessels are on long-term charter. This is due to the potential to generate revenue if they are out-chartered. This opportunity cost would likely be calculated using prevailing spot charter rates provided by a price reporting agency, as these would be the most relevant proxy and would take into account prevailing market conditions.

Therefore, spot charter rate assessments and forecasts are relevant to the opportunity cost approach of the ACCC netback methodology, even where vessels are contracted on long-term charter.

As building new vessel capacity is the solution to alleviating a tight shipping market, the new-build vessel cost would be a useful starting point for calculating longer-term charter rates. Developing an appropriate methodology and model for long-term charter forecasts requires more information. Preliminary investigation suggests that market consultants, LNG traders and brokerage firms each use their own proprietary cost models and rules of thumb or specific business intelligence over market conditions, vessel costs, future technology advances (eg boil off) and depreciation schedules. To our knowledge, there is no publicly available source of this data.

There are emerging LNG (derivative) freight assessments which could be worthy of ongoing investigation as to whether tradable forward curves offer greater confidence levels in terms of long-term charter outlooks. These include SPARK, S&P Global Platts along with Argus Media.

5.1.1. Review of current netback cost method

Shipping costs to (and from) a destination port is a key input required for the LNG netback calculation. The ACCC relies on two LNG freight cost assessments in calculating the shipping cost component of its Gladstone FOB prices:-

- Historical - using Platts daily assessments of freight costs between Gladstone to Tokyo (Futtsu Bay) on a particular date.

- Forecast – using Argus Media’s forward LNG freight cost estimate for Gladstone to Tokyo.

Each assessment (historical and forecast) is developed by a credible and independent PRA which purposely look to ensure these are not driven by consensus or majority voting from industry participants. Inputs into the assessments are contributed by a wide range of market participants (ship owners, brokers, producers, consumers, traders and other active spot market participants) which diversifies the dataset and reduces the risk of self-serving inputs which distort the overall picture.

Assessments are not dependent on a minimum transactional volume or liquidity threshold – this means that the confidence level in underlying assessments may differ from day to day. However, these are relied on and used willingly by market participants globally as a benchmark and an up-to-date representation of current and future LNG freight market values. There are different basic methodological approaches and reference assumptions between the reporting and forward assessments (eg for fuel costs), but these are transparently disclosed and unlikely to yield significant difference were these fully aligned.

Overall, the freight cost element appears to be less controversial than other cost categories, and is broadly accepted to have limited influence on or be the major driver of the netback calculation.

The current methodological approach for freight costs in the historical netback price calculation is robust, aligned with the JKM assessment methodology and meets the transparency objectives of the LNG Netback Price Series. While the liquidity of bids/offers and number of contributors mean it has sufficient depth to suggest sufficient accuracy and robustness.

5.2. Analysis of available benchmarks/index-listed futures

Numerous reporting agencies, brokerage firms and market consultants produce and publish short-term and spot charter benchmark assessments. These are largely based on survey participants' views on what a charter day rate might be if a vessel were to be secured on a particular date and not necessarily based on actual deals. The relatively low volume of trade in the LNG shipping market on a daily basis might indicate that these place greater reliance on editorial assessments rather than actuals.

Furthermore, each market observer may apply different assessment and reporting methodologies which makes exact comparison of values across publications more challenging. In the following table we summarise different freight cost market observers and participants - note this is indicative and based upon publicly available information on their respective methodologies.

Table 1: Analysis of Potential Sources of LNG Freight Rate Forecasts

Type	Data source	Name of index/ assessment	Data frequency	Period	Location	Vessel specifications	Indexation/ Forecasting approach	Limitations	Add. Notes
Consult Report / Forecast	Argus Media	Argus Forecast (R.V.)	Monthly rate - US$/d	Up to 12 months; 24 month view for ACCC	East of Suez (Gladstone-Tokyo), Round Voyage	**Propulsion/Vessel Type** Dual-fuel diesel electric (DFDE) **Vessel Size** 155,000-165,000m^3 **Fuel Use** Boil-off (assumed to be burnt on the outward leg to power the vessel, while the return leg is powered using bunker fuel) **Boil-off** 0.1-0.125pc	Based on market survey, supplemented by considerations of differential between the HENRY HUB and highest delivered gas price in Europe and NE Asia from the 13th month onwards.	* Limited by duration (up to 24 months) * Limited visibility in the process of gathering and analysing market surveys * Lack of bid/offer/trade liquidity beyond 9-12 months	
	Fearnleys LNG	Fearnley Weekly Report https://fearnpulse.com/	Weekly rate (US$/d) Weekly (US$m/ ship)	Up to 12 months (1-year term contract) New build estimate	Global average (presumed)	**Propulsion/Vessel Type** Tri-fuel diesel electric (TFDE), MEGI & X-DF **Vessel Size** 155,000-165,000m^3 **Fuel Use** Boil-off **Boil-off** 0.1-0.125pc (presumed)	The 1-yr term charter is a proxy to estimating the freight rates for the following 12 months (market expectations) Presumably broker / shipyard expectations (TBC)	* Limited by duration (up to 1 year) * Limited visibility in the process of gathering and analysing market expectations * Limited visibility in vessel route & specifications * Limited visibility in the process of gathering and analysing market expectations	Widest- used market broker report; references made to Fearnley's forward freight rates in the investor presentations of Flex LNG, Gas Log MLP, Teekay LNG, Golar LNG, etc

Index-listed Futures	CME/ NYMEX Baltic EX	BLNG1(g) (R.V.) BLNG1 (R.V.)	Monthly rate (US$/d)	Current year (monthly) and up to following 2 calendar years	East of Suez (Gladstone - Tokyo Bay), Round Voyage	**Propulsion/ Vessel Type** Tri-fuel diesel electric (TFDE) **Vessel Size** 160,000 m3 **Fuel Use** BLNG1(g): Boil-off BLNG1: Marine fuel oil (VLSFO) **Speed** BLNG1(g): 17 knots on 210 bcm LNG/day laden, 16 knots on 190 bcm LNG/day ballast BLNG1: 19 knots on 100 ton/day laden, 95 ton/day ballast **Boil-off (BLNG1(g))** 0.1pc	Discussion (consultative process) among panel of traders and brokers arranging charters	* Currently has low liquidity of market/trades * Limited by duration (up to ~3 years) * The Baltic Exchange has a relatively short history of assessing LNG freight rates; BLNG1 assessment began in 2019, and BLNG1(g) assessment began in 2021	* Perceived as a widely used reference for freight rates among ECGM stakeholders * Slightly longer-term than the duration of Argus' forward curve
	(ICE) Spark Commodities	Spark25 F/Fo Pacific 160 TFDE (R.V.)	Monthly rate (US$/day)	Up to 12 months	NWS - Tianjin, Round Voyage *w/ future potential for further routes among Japan, Korea, Taiwan, China, and Australia*	**Vessel Type** Tri-fuel diesel electric (TFDE) **Vessel Size** 160,000 m3 **Fuel Use** Boil-off **Speed** 17 knots **Boil-off** 0.1pc	Assessed via a simple average of eligible broker assessments computed at the end of the submission window Eligible submitter categories include brokers, portfolio players, vessel owners. All new Brokers must be nominated by at least 5 market participants in order to contribute to the Spark Price assessment. Brokers must be actively involved in the spot market and must demonstrate this. A survey will be sent out to all Spark users every 12 months (starting in September 2021) allowing the market to challenge the involvement of any brokers or suggesting the addition of new brokers.	* Doesn't currently assess the Gladstone-Tokyo route * Currently has low liquidity of market/trades * Limited by duration (up to ~1 year) * Spot Commodities has a relatively short history of assessing LNG freight rates; Spark 25 assessment began in 2021	

5.3. Assessment of other potential approaches

5.3.1. Long-run marginal cost (LRMC) of shipping

If the Netback Series review determines that a longer-term view of netback pricing is desirable, then a new methodology will be required to provide longer-term forecast for LNG freight rates. Current price assessments and LNG shipping derivatives do not extend beyond a 24- and 36-month period, while reliability of these market values beyond 12 month period is questionable given extremely limited market liquidity.

Given LNG trade is ultimately capped by the availability of the vessel fleet, one approach to estimate future freight costs beyond a 2-3 year period might be to calculate an indicative charter day rate based upon a new-build vessel.

Taking a long-term charter view would assist in extending out the forecast period, while smoothing the volatility curve, much in the same way that a new LNG project developer or LNG portfolio player might consider chartering a vessel long term.

Example shipping model inputs

While most market participants will use their own internal shipping cost models using own assumptions, including company-determined depreciation schedule, proprietary business intelligence and new-build vessel cost assessments or quotations from shipyards. Brokers and market consultants will similarly have proprietary views. Though these, like those of market participants, are unlikely to be available in the public domain.

A typical shipping cost model uses standard assumptions on a range of variables (listed below) to calculate a shipping tariff (US$/mmbtu). Key variables include:

Costs

- Capital recovery costs (taking into account the cost of debt and equity as well as depreciation)
- Return on investment targeted rate
- Operating costs
- Port and canal charges (where appropriate)
- Boil-off gas consumption and cost
- Fuel oil consumption and cost

Ship/voyage characteristics

- Ship size
- Ship speed
- Delivered quantity of gas (adjusting for boil-off and heel)
- Distance from loading port to delivery port
- Time spent in loading and delivery ports (plus any periods spent transiting canals if appropriate) and manoeuvring time in the vicinity of these facilities,
- Number of operating days per annum (assumed to include some downtime for repair and maintenance, plus a buffer to offset any unforeseen disruptions, cater for seasonal peaks in cargo delivery programmes and provide a degree of flexibility along the supply chain).

6. Long-run vs. Short-run Cost Factors

This section addresses the appropriateness of different approaches to netting back costs in the derivation of an LNG netback price at Wallumbilla, and considers which costs should be considered and which should be excluded in that calculation.

Section Summary

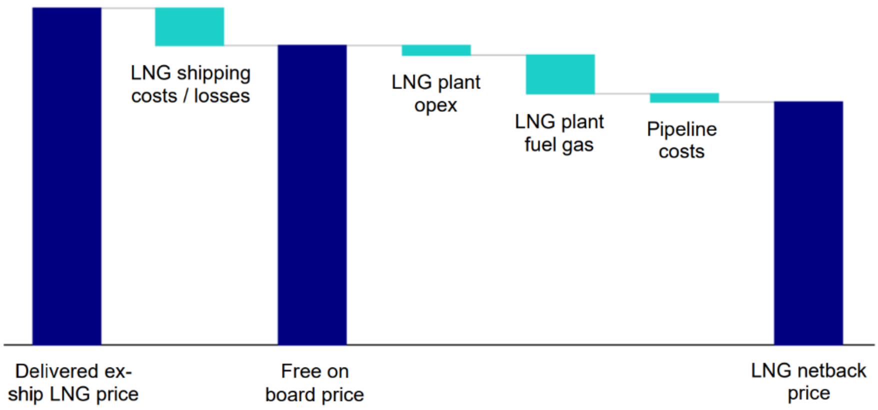
- The ACCC LNG Netback Series is based on an "opportunity cost framework". For consistency purposes this approach should apply to all elements of the netback calculation, including costs.
- As incremental gas sales decisions are taken on a look-forward basis, only short-run marginal costs should be deducted in the netback calculation (when the LNG projects have spare capacity).
- Deductions of fixed costs and/or capital costs would not deliver a representative and equivalent domestic gas netback for an LNG producer choosing between domestic gas or incremental LNG sales.
- Major maintenance is an integral part of the long-term operations of a liquefaction project. These are unavoidable costs and should not be deducted in the netback calculation for incremental LNG supply.

Background and ACCC Netback Series Approach to Costs

An LNG netback price represents the effective price an LNG producer would expect to receive for gas, at a specific reference location, if that gas were converted to LNG and exported. This is done by taking the price payable for LNG and subtracting or 'netting back' the relevant costs that will be incurred by a producer to get that between the reference location and the location where the LNG is delivered.

For the ACCC LNG Netback Series these incurred costs reflect the cost of transporting gas to the liquefaction facility, the cost of liquefaction and indicative costs of shipping LNG from Gladstone to Tokyo (as a proxy for delivery costs into northeast Asia) as outlined in the graphic below.

Figure 30: ACCC-stylised LNG Netback Price Calculation (Costs Highlighted)



Source: ACCC Guide to the LNG netback price series

More specifically, costs are calculated using the following data inputs:

1. LNG freight costs - the ACCC publishes freight cost assessments provided by S&P Platts and Argus Media as a proxy for the prevailing cost of transporting LNG from Gladstone to Tokyo.

2. Conversion to A$/GJ from US$/MMBtu - the ACCC uses contemporary exchange rate data and a GJ to MMBtu conversion ratio of 1:1.055

3. Subtraction of LNG plant (marginal) costs and LNG plant fuel gas costs – the ACCC uses operational data provided by the Queensland LNG producers to calculate a proxy for these values.

4. Adjustment made for marginal pipeline transportation costs between Wallumbilla and Gladstone – the ACCC uses also data provided by the Queensland LNG producers to calculate a proxy for these values.

The ACCC's LNG Netback Series nets costs back to Wallumbilla because this is the pipeline interconnection point that links the LNG producers' gas production facilities to the ECGM.

Queensland LNG projects have "spare" capacity (~3.5Mtpa) above their contracted levels which is available for additional LNG production and sales (subject to feedgas availability and the prevailing price for spot sales or new term contracts). This "spare" capacity can be used to contract additional LNG sales on a short or spot basis and/or on a term basis (short, medium or long-term contract).

6.1. Long-run versus short-run cost in calculating LNG netback prices

The key question around costs in the ACCC Netback Series centres on determining which LNG plant costs are relevant for inclusion in the netback calculation. This is important as significant upfront capital investment is required to develop a typical LNG project, though once a project is operational its running costs are considerably lower. Therefore, choosing to apply a long-run (full lifecycle cost) or short-run (avoidable operational cost) approach will have a material impact on the amount of cost that is 'netted back' and the resultant netback price.

The guiding principles of the "opportunity cost" framework applied by the ACCC consider that decisions around incremental exports are made solely on a look-forward basis. Therefore, any element of cost which has been incurred in the past should be considered sunk, and excluded from this calculation. Furthermore, any fixed operational costs that would be incurred irrespective of whether incremental LNG is produced or not, should similarly be excluded.

The cost deductions in the netback calculation should therefore be based on the short-run marginal costs (or incremental costs) incurred in producing this additional LNG. The capital costs incurred to build the LNG facilities can no longer be avoided. The only costs that can be avoided in the production of additional LNG are the incremental costs (or short-run marginal costs). These typically reflect additional fuel or transport requirements or incremental tariff payments in respect of additional throughput.

This is because if a Queensland LNG producer has spare liquefaction capacity, it has a choice whether to produce and sell incremental LNG or sell the gas into the ECGM. If a Queensland LNG producer chooses to sell spot LNG, it needs to transport the gas from the upstream processing plant(s) to the liquefaction facility at Gladstone and process the gas into LNG and ship the LNG to North Asia (or sell FOB Gladstone). For supplies to the domestic gas market, a Queensland LNG producer needs only to transport the gas from the upstream processing plant(s) to a common user gas pipeline or hub.

If Queensland LNG project output were to reach its full LNG export capacity on a sustained basis, it would be unable to produce any additional LNG and additional gas production would necessarily be monetised through sales to the domestic market or new capital investment to expand production capacity. Under these circumstances deducting long-run marginal costs (the full unit costs to develop a new LNG train or LNG facility) would become more appropriate for the netback calculation.

6.2. Consideration of short-run marginal or average costs

A **marginal cost** is the variable cost associated with one additional unit of output.

The **average cost** is the total cost of an output divided by the total output.

In calculating the short-run marginal cost for the Queensland LNG projects, data provided by the LNG producers to the ACCC is and should continue to be used to demonstrate the actual incremental cost associated with the incremental LNG supply.

To produce and export incremental LNG, a Queensland LNG producer would utilise its existing pipeline(s), liquefaction plant, LNG storage and jetty and deliver LNG to a receiving LNG vessel. These facilities are already established and operational in Queensland and have spare capacity that enables additional volumes of LNG to be produced above contracted commitments. The costs incurred in producing additional LNG are therefore the variable or operating costs for the transport, liquefaction and shipping elements of the value chain.

Contracted LNG levels will guide the expected minimum LNG output. There are fixed costs to operate and maintain the LNG facility and these costs are incurred whether the plant runs at the minimum contracted output or at the full LNG capacity. Similarly, there are costs associated with major maintenance (which is generally required every ~3-4 years) and these costs are also incurred independent of the utilisation or otherwise of spare capacity. Variable costs (including fuel use, e.g. gas consumed to run the LNG plant turbines and compressors) however, are incurred proportional to the LNG volume produced.

The three Queensland LNG plants have the same liquefaction technology and therefore would be expected to broadly have the same fuel consumption. However, on average the gas consumed as fuel in the LNG process ranges ~7 to 11%. The differences in fuel consumption between the projects is due to their operating configuration and facility utilisation levels.

In assessing the fuel used to supply incremental LNG, marginal fuel use will be lower than a project's average fuel use. The marginal fuel use is an incremental cost which would otherwise be avoided, by an LNG producer if it supplied gas to the domestic market, rather than produce and export the gas volume as LNG. It is therefore appropriate to use marginal fuel use, rather than average fuel use, when assessing the incremental fuel use cost for netback deductions.

The ACCC assesses the plant efficiency (marginal fuel use) at the level of the LNG facilities' utilisation needed to meet its long-term contracts. This is a reasonable approach as the LNG projects would be expected to meet their long-term contracts each year. However, there are periods where LNG buyers may reduce their contract nominations below contract level (generally less than 10%) in a particular year, which is made up in following years at higher than contract levels. The LNG facilities may also run for periods at higher utilisation rates, particularly when market conditions support the export of additional spot cargoes.

These variations would result in slight differences to plant efficiency and therefore marginal fuel use. Whilst these would not be expected to have a material impact in terms of the fuel use netback deduction, it may be worth further investigation to assess fuel use rates at different plant utilisation levels (based on historic data from the projects). When assessing the netback price over a 3 to 5 year period, and where there is an expected material change forecast in the LNG projects utilisation, then a variable fuel use rate might be applicable (notwithstanding that the long-term contracted level is expected to be maintained by the projects throughout this decade).

6.3. Consideration of long-run marginal or average costs

The long-run marginal cost analysis is used primarily to support capital investment decisions. This could be for a new LNG project or an existing project that is looking to expand its production capacity (e.g. expansion train or train debottlenecking investments). The long-run marginal cost approach considers the full investment cost to develop new supply, and may be used to benchmark its unit costs relative to an expected LNG sales price or projects competing for capital in a company's portfolio.

The netback domestic price alternative for a potential new LNG development would therefore reflect the potential contract LNG price minus shipping, minus the long-run costs (including a return on the capital invested).

Given the opportunity cost approach of ACCC LNG Netback Series a short-run cost deduction should be applied against the LNG reference price, as the decision to supply incremental volumes does not require additional capital expenditure. This is because the Queensland LNG projects have spare capacity which enables them to make these decisions on a short-run basis.

Deducting long-run costs would potentially create a distortion in the ECGM in terms of price signals. This would result in a lower netback price, which could act to disincentivise new gas supply into the market (particularly new gas supplies where transportation costs add materially to the delivered gas price, e.g. potential gas developments in the Northern Bowen Basin, Galilee Basin and Beetaloo Basin).

6.3.1. LNG plant costs

LNG plant capital costs are incurred largely during construction of the facility and therefore should be considered capital costs. LNG plant costs do not have any bearing on the decision to produce incremental LNG from an existing project, as these costs have already been incurred (i.e. sunk costs).

It is important to note that LNG spot sales are not expected to recover any cost of capital through an incremental export transaction. The spot price received by the exporter may secure it a margin in excess of its short-run costs, but that will does not necessarily translate to a return on capital.

6.3.2. LNG contract term

An LNG producer with sufficient spare capacity can sell LNG either on a spot basis, short to medium term strips and/or a long term contract. These different contractual arrangements have varying supply commitments, ranging from a single cargo through to multiple cargoes over multiple years. The duration of the contract, whether it be for a single cargo or multi-year commitment, should not impact how LNG capital costs are treated in the netback calculation. All capital costs should be treated as sunk irrespective of the contract term of new, incremental LNG sales.

6.3.3. Treatment of LNG plant maintenance costs

Major maintenance operations are generally carried out on LNG facilities every ~3 to 4 years. During scheduled maintenance events LNG trains will be taken off-line (turndown) for 3 to 6 weeks. This is typically done sequentially for optimisation and efficiency purposes, and also to smooth out any LNG sales interruptions to customers.

There is a limited amount of flexibility as to when scheduled maintenance can be performed, although maintenance windows can be shifted about in certain exceptional circumstances (e.g. COVID-19 restrictions on mobilising personnel).

Nevertheless, major maintenance is critical to overall project operations and needs to occur irrespective of whether an LNG plant runs at or below nameplate capacity.

Major maintenance should therefore not be considered an “avoidable” cost and deducted from the netback calculation for incremental LNG production. This is because incremental production (and higher plant utilisation) does not fundamentally change the periodic need for scheduled maintenance. LNG maintenance costs should therefore be considered a long-run marginal cost.

6.3.4. Other factors / implications relevant to the LNG netback calculation

Deducting long-run marginal costs in the netback calculation would create an artificially low domestic gas price netback, one that was potentially below the cost of supply. This would not represent the LNG producers opportunity cost for domestic gas supply and could create the following distortions in the domestic gas market:

- LNG exporters would be incentivised to export LNG rather than supply the domestic gas market, as they would receive a higher netback price from their LNG sales than they would do from the lower price domestic gas sales;

- LNG exporters with spare capacity would be incentivised to buy domestic gas and sell as LNG – as the lower domestic gas price plus short-run marginal costs would generate a higher margin when sold as LNG; and

- New gas supply sources may not secure a market price that incentivises their development. This could exacerbate tight domestic gas market conditions in the longer term.

7. Glossary

ACCC	Australian Competition and Consumer Commission
ACQ	Annual contract quantity
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Markets Operator
AENA	Average North East Asia Marker
A$	Australian dollar
AUD	Australian dollar
APAC	Asia-Pacific
APLNG	Australia Pacific LNG
bbl	Barrel
Bcm	Billion cubic metres
CAGR	Compound annual growth rate
CME	CME Group
CNOOC	China National Offshore Oil Company
CNPC	China National Petroleum Corporation
COVID-19	Coronavirus
CSG	Coal seam gas, also known as coal bed methane (CBM)
DES	Delivered ex ship
ECGM	East Coast Gas Market
FID	Final investment decision
FOB	Free on board
GJ	Gigajoule
GPG	Gas-fired power generation
GSOO	AEMO’s Gas Statement of Opportunities - supply and demand report
HH	Henry Hub
Henry Hub “plus”	Henry Hub plus sellers’ gas procurement + liquefaction fee + shipping
HOA	Heads of Agreement
JCC	Japanese Customs-cleared Crude, (colloquially Japanese Crude Cocktail) the weighted average price of crude oil imported into Japan
JKM	Platt’s Japan Korea Marker
JKT	Japan, Korea, and Taiwan

JV	Joint venture
ICE	Intercontinental Exchange
Incl.	Including
km	Kilometre
LNG	Liquefied natural gas
LT	Long-term
m3	Cubic metres
M+12	Current month plus 12 monthts
MEGI	M-type Electronically Controlled Gas injection engine
Mbtu	Million British thermal units
mmbtu	Million British thermal units
Mt	Million tonnes
Mtoe	Million tonnes oil equivalent
Mtpa	Million tonnes per annum
MOU	Memoranda of Understanding
NA	North America
N. America	North America
NSW	New South Wales
NWE	North-west Europe
NYMEX	New York Mercantile Exchange
PJ	Petajoules
PJ/a	Petajoules per annum
PNG	Papua New Guinea
PRAs	Independent Price Reporting Agencies
Q1, Q2, Q3, Q4	First quarter, second quarter, third quarter, fourth quarter
QCLNG	Queensland Curtis LNG
QLD	Queensland
RoW	Rest of World
SA	South Australia
S&P	S&P Global Platts
SPA	Sales and Purchase agreement
SWQP	South-west Queensland pipeline

TFDE	Tri-fuel diesel electric
TJ	Terajoules
TJ/d	Terajoules per day
TPED	Total primary energy demand
TTF	Netherlands' Title Transfer Facility
UAE	United Arab Emirates
US	United States of America
US$	United States dollar
US$/day	United States dollar per day
US$/mmbtu	United States dollar per million British thermal units
USGC	United States Gulf Coast
VMA	Volume weighted average
X-DF	Low pressure gas engine

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