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Joshua Runciman
Australian Competition and Consumer Commission
ACCC LNG Netback Price Series Review Committee

Email to: LNGnetbackreview@accc.gov.au and Joshua.Runciman@accc.gov.au

Dear Joshua

Submission on ACCC LNG Netback Pricing Review

Since its introduction in 2018 the ACCC LNG Netback Price Series has been useful in providing a further transparency measure to better inform market participants in the east coast domestic gas market.

The Prime Minister and the LNG producers (including Santos GLNG) executed a Heads of Agreement dated 31 December 2020 in which the parties agreed that:

"LNG netback prices based on Asian LNG spot prices play a role in influencing domestic gas prices in the east coast gas market (as referenced by the ACCC LNG netback price series). Individual prices offered to domestic gas users will be internationally competitive and have regard to the producer's cost of supply and factors that may be relevant to users' individual circumstances, including the terms and conditions of their gas supply agreement and any applicable transportation or retailer charges."

Santos notes and agrees with the ACCC's comment that the LNG netback price represents the indifference point for LNG producers between supplying uncontracted spot gas to the east coast domestic market or to LNG export markets.

However, both Santos GLNG and peak industry body APPEA wrote to the government noting that the Agreement was executed on the basis of the ACCC LNG netback price series methodology in use at the time of signing and that any change to the methodology would require reconsideration by the LNG producers as to whether the Heads of Agreement continued to accurately reflect their position.

JKM vs Henry Hub

The S&P Platts JKM (JKM) reflects the assessed spot market value of cargoes delivered ex-ship into Japan, Korea, China and Taiwan, based on trades, bids, offers and indications reported to Platts on a given day. The JKM locations of Japan, Korea, China and Taiwan, comprise around 80% of Asian LNG demand and more than 55% of global LNG demand (spot and term). Over time, as demand patterns change, Platts may choose to adjust the JKM to include LNG volumes delivered to other ports in Asia. In the fourth quarter of 2020, more than 90% of LNG from Gladstone went into Japan, Korea, China and Taiwan, and 100% of LNG from Gladstone went to Asian destinations.

Importantly, **any Henry Hub influence is already accounted for in the JKM because US cargoes delivered ex-ship into Japan, Korea, China and Taiwan will have been considered in its calculation**. Last year around 50% of US LNG was delivered into Asia with more than 90% of those volumes delivered into Japan, Korea, China and Taiwan.

Figure 3 in the ACCC's March 2021 issues paper shows a convergence of global gas price markers to the Henry Hub that started in 2019 and culminated around May 2020. The paper does not include data after May 2020 which shows that the JKM has since moved away from Henry Hub pricing and recoupled with oil prices (Attachment 1, Figure 1). The convergence shown in the ACCC's issues paper was a short-term phenomenon resulting from a confluence of events: LNG market over-supply as US exports ramped up in 2019; European storage hitting capacity; and LNG demand collapsing with the global pandemic in early to mid-2020.

As supply and demand have rebalanced, JKM has recoupled with oil prices and is forecast to continue to trade in line with term oil-linked LNG contracts over forecast period of the next two years with the Japan spot price (delivered ex-ship) expected to be in the A$8-10/GJ range (Attachment 1, Figure 2). New Asian oil-linked contracts at 11.5% Brent plus transport would be in the same range. The JKM forecast represents a price premium of between A$4 and A$6/GJ on the Henry Hub, but more importantly represents the full cycle economic cost of supply from the US. Santos estimates the notional cost of US supply to Japan at around A$8.80/GJ (Attachment 1, Figure 2).

Seasonal price volatility will be a continuing feature of the north Asian market with winter demand peaks.

The majority of global LNG contracts signed over the past 10 years have been oil linked. Henry Hub indexation appears to have been preferred by some customers in years when oil price has been high and when US LNG projects have been entering into contracts (Attachment 1, Figure 3). Sixty-eight per cent of 2021 contracts are oil linked compared with 19% being linked to Henry Hub. Of 2030 contracts, 53% are oil linked and 30% are linked to Henry Hub (Attachment 1, Figure 4). All LNG contracts ex-Gladstone are oil linked to at least 2030 (Attachment 1, Figure 5).

While the US had looked set to become the biggest of the LNG producers, a number of potential US projects have been shelved and the policy environment may be less supportive following last year's elections. The market behaviour of Qatar will be equally or more influential on Asian LNG prices for the remainder of this decade and beyond. This is not only because Qatar has huge gas resources and low production costs, but because its economy is heavily dependent on its gas sector, therefore Qatar must maintain or grow LNG market share. The gas industry contributes two-thirds of Qatar's Gross Domestic Product and 80% of its export earnings. Access to global LNG markets will also be important to Russia's economy with energy exports (including pipeline gas and LNG) making up around 80% of its export earnings and the oil and gas sector contributing about 40% of government revenues for its budget.

The fact that the JKM reflects the prices of cargoes physically delivered into Asia means that any influence of price markers in other countries is fully accounted for. This includes European markers such as the Netherlands Title Transfer Facility. **With Japan, Korea, China and Taiwan receiving the majority of LNG exports from Gladstone, the JKM is clearly the most appropriate price marker for the ACCC's LNG Netback Price Series**.

Importantly, **when the three Gladstone LNG plants are running at effective capacity, east coast domestic gas prices will be determined by the marginal cost of supply, not LNG netback prices.** Estimated total export capacity from Gladstone is around 25.3mmtpa (nameplate capacity). In 2020 total LNG exports from Gladstone were 22.2mmtpa. Effective capacity will only be achieved with major new gas supply sources being developed for both export and domestic markets, requiring billions of dollars of new investment.

The ACCC's issues paper notes that about 34% of global LNG trade in 2019 was in the spot market, however, **the spot market in Asia accounted for less than 5% of Asian LNG demand in 2020 and is forecast to account for 13% in 2022** (Attachment 1, Figure 6). The vast majority of Asian LNG demand is still contracted and Australian LNG exporters will continue to require long-term contracts to underwrite the multi-billion dollar investments needed to develop new gas supply for either LNG plant backfill or for new LNG trains.

Santos' A$5.6 billion final investment decision[1] in March 2021 for the Barossa gas project offshore the Northern Territory is a good example. Barossa will backfill the Darwin LNG plant with 80% of Santos' equity volumes already contracted to Japan's Diamond Gas International (a subsidiary of Mitsubishi). This contract is priced against JKM further reflecting its status as the recognized and preferred price index in the Asian region. More supply contracts in the future are likely to be priced against JKM, increasing physical liquidity and bolstering financial products such as JKM derivatives.

Cost of supply into the east coast market

The Prime Minister and the Gladstone LNG producers recognized in the new Heads of Agreement that domestic gas prices offered to domestic gas users will have regard to the producer's cost of supply and other relevant factors including the cost of terms and transport. The producer's cost of supply is the dominant factor influencing domestic gas prices in the east coast market, particularly for those producers without oil or liquids production to subsidise gas production and/or without exposure to the LNG market, which brings the economic benefits of scale and access to higher prices.

Unless producers can be certain that federal government intervention will not undermine their business cases, which assume the ability to recover their cost of supply and an appropriate return on their investments (greater than their weighted average cost of capital), **new gas supply sources to maintain long-term reliability of supply and add competition to the east coast gas market will not be developed.** This outcome would only lead to higher domestic gas prices as the east coast gas market relies on continuous investment in drilling new wells and without the right price signal that investment would cease. In 2020, some producers responded almost immediately to reduce their number of drilling rigs and scale back their drilling investment.

Despite the volatile environment of 2020 when the coronavirus pandemic led to record low commodity prices and a dramatic reduction in worldwide oil and gas investment, **the Santos GLNG joint venture continued to develop new gas supply in Queensland's Surat/Bowen coal seam gas fields, drilling over 700 wells and investing around A$2 billion in gas field developments over the past two years.** In what remains a very challenging global environment, the joint venture has made final investment decisions for **new investment in 2021 of around A$800 million in further drilling and gas field developments in Queensland.** Santos is investing an additional A$180 million in non-GLNG wells and gas development in 2021 in this region.

Santos has observed that pricing at the Wallumbilla hub tends to stabilise around A$6/GJ, with the lowest-cost LNG producers (who have the advantage of high quality resources combined with scale) withdrawing volumes at a price of around A$5.15/GJ, indicating that the marginal cost of supply in the region is around A$6/GJ.

In the Cooper Basin in South Australia and southwest Queensland, Santos is investing A$670 million drilling new wells in 2021 to maintain and grow supply for the east coast domestic gas market. The estimated cost of new Cooper supply ex-field is in the A$5-7/GJ range. This includes the benefit of liquids credits, without which the cost of gas supply ex-field would be more than A$9/GJ.

Transport to southern markets from Queensland and South Australia could cost an additional A$2-4/GJ.

In the Beetaloo Basin in the Northern Territory we are spending A$105 million on exploration which we hope will open up a vast new gas supply source. Estimated cost of supply ex-field is currently in the A$4-5/GJ range with transport to Darwin estimated at A$1-2/GJ and to east coast markets A$5-9/GJ reflecting the large distance to markets and the high cost of pipeline transportation (requiring new infrastructure spend).

[1] $ includes Darwin LNG life extension

In New South Wales, **the Narrabri Gas Project** is now approved and ready for appraisal, with **up to A$215 million to be invested over the next two years. As a 100% domestic gas project, the domestic gas price must cover the full cost of development** and provide an appropriate return on investment. In 2019, the estimated cost of supply ex-field was in the A$6-7/GJ range with transport to the Sydney hub estimated at A$1-2/GJ.

Increasingly, **our institutional investors, our debt financiers and our joint venture partners from France, Italy, Japan, Korea and Malaysia are inquiring about the potential for federal government intervention in the east coast gas market,** indicating that this is a factor in their decision-making processes.

Internationally competitive prices

In the Heads of Agreement, the Prime Minister and the Gladstone LNG producers agreed that domestic gas prices offered will be internationally competitive. In February 2021 the ACCC claimed that *"domestic customers are still paying more than export parity….[and]….more than overseas customers."* The ACCC has not presented evidence to support this claim which is contrary to public reporting by Santos and other ASX-listed companies of average realized LNG prices and average realized domestic gas prices. This reporting shows that average realized LNG prices are always higher than average realized domestic gas prices. International Gas Union data also consistently reports that Australian customers pay less for gas than customers in Asia.

The ACCC's January 2021 interim Gas Inquiry report itself noted in relation to an observed A$1/GJ difference between domestic prices offered in mid-2020 and the LNG netback price:

"The $1/GJ disparity observed in mid-2020 is largely attributable to a number of higher-priced offers made for delivery at locations other than Wallumbilla, which may involve additional transport costs for suppliers."

Further, the marginal cost of supply in the region will set a floor price at Wallumbilla, regardless of the LNG netback price. Based on Santos' market observation, this is around A$6/GJ.

The US domestic market which some gas users compare to the Australian east coast market has vastly different characteristics. Although associated gas is only around 10-20% of total US gas production, it is the pursuit of higher-priced natural gas liquids (wet gas developments) that has kept the price of associated gas relatively low. The Henry Hub in Louisiana sets a clearing price for gas because of its high liquidity and interconnectedness across the US market, which is serviced by more than 485,000km of pipeline (providing access not only across the US but into Canada and Mexico), compared to Australia's ~40,000km of pipelines. The Henry Hub infrastructure offers interconnections into nine intrastate and four interstate pipelines, while direct connections into three storage caverns add further flexibility, allowing gas to be traded.

Just as important as physical infrastructure is the sophistication of financial products and the scale of gas trading in the US market, which does not occur in Australia because of the small scale of the domestic market. By comparison, the **US domestic market has enormous scale, being about 50 times the size of Australia's east coast domestic market.** In fact, more gas is flared and vented in the US each year than Australia's entire east coast domestic demand.

This Henry Hub price is one factor influencing the actual price paid by gas users across the US. There are hundreds of other trading points across the US, each region has its own effective index, pipeline transport positions have to be paid for to enable physical delivery of gas, there are system bottlenecks that constrain the movement of gas, timing issues arising from trades and weather events such as hurricanes that shut in production or otherwise cause changes in supply locations. As in Australia, distribution and retail charges can add significantly to the price gas users ultimately pay. Analysis of Energy Information Administration data by MST Financial found that in 2019, the Henry Hub price averaged about A$3.60/GJ, but **the average price paid by industrial gas users across the 50 US states was about A$8.70/GJ** with 23 states having prices above A$8/GJ and 11 states having prices above A$10/GJ.

The one thing the US has in common with Australia is that the gas prices paid by users ultimately reflect the producers' cost of supply and transport to users as well as opportunity costs (including deciding whether to produce higher-priced natural gas liquids even when associated gas prices are very low or even negative).

The Gippsland and Cooper Basins, developed more than half a century ago, had the benefit of being rich in high-priced oil and natural gas liquids which is why Australian customers historically enjoyed many decades of low associated gas prices. In other words, the gas supply did not have to carry the full cost of the development. In fact Australia's use of LPG in transport, incentivized through a federal government policy of zero excise, developed as a way of beneficially using what would otherwise have been difficult to market or dispose.

Today, much of the new gas supply on the Australian east coast is dry gas, particularly the Queensland coal seam gas fields, which now supply 13% of total east coast demand. Therefore the domestic gas price must cover the full cost of development and production.

As mentioned earlier, the US domestic is 50 times the size of Australia's east coast domestic market. In addition, the US domestic market is 13 times the size of its LNG export capacity, whereas in Australia, Gladstone LNG exports are more than 3 times the size of the east coast domestic market. **That means that in Australia, the scale that underpins major new gas supply developments must come from LNG exports.** Domestic customers do not have the ability or risk appetite to underwrite contracts of the scale, duration and price needed to enable the multi-billion dollar investments required to make Queensland coal seam gas development economic, nor will they be able to underwrite development of future provinces such as the Beetaloo Basin in the Northern Territory. **Without LNG exports** underwriting the development of Queensland coal seam gas, **domestic gas prices would be higher than they are today** and many resources that are currently producing would never have been developed.

A strong LNG sector that can continue to attract foreign investment to Australia is not only desirable for export income, jobs and business opportunities, regional development and other economic benefits, it is **critical to Australia's domestic gas security and price competitiveness, providing the necessary scale to make new gas supply developments economic.** Without the LNG sector, Australia's vast undeveloped gas resources are likely to remain economically stranded and domestic customers would be exposed to import prices.

No LNG project in Australia has ever been funded from Australian balance sheets. All have required partnerships, foreign investment and long-term offtake agreements with LNG customers. This will continue to be the case if Australia is to develop new gas resources such as the Beetaloo Basin in the Northern Territory which is very remote from Australian domestic markets which lack the scale required to underpin development.

Utility of the LNG Netback Price Series

The Prime Minister and the Gladstone LNG producers also agreed in the Heads of Agreement that:

"Spot prices offered to the domestic market will have regard to the spot price LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets. Term prices offered to the domestic market will have regard to forward term prices LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets."

The ACCC LNG Netback Price Series has relevance only to spot prices and short-term contract prices of one to two years, but it is just one factor influencing price. The cost of supply remains an important consideration with producers needing to decide whether to produce above contractual obligations or not to produce any gas excess to these requirements. And very importantly, our primary objective is meeting the long and short-term demands of the domestic market. We move gas to the areas of highest demand as best we can, regardless of theoretical netback alternatives. This results in a delinking from netback pricing from time to time, most recently early this year when netback pricing significantly exceeded the price being achieved in meeting the domestic market.

Only one or two joint ventures in Queensland have large undeveloped, uncontracted reserves for which they would need to consider forward term prices for LNG versus long-term domestic gas contract prices. Even then, domestic contracts would be unlikely to match the scale and duration of LNG contracts. Some of the joint venture partners are foreign investors and LNG buyers who purchased rights to these reserves specifically to service their LNG needs in the future. They hold lawful property rights and have invested in accordance with Australian laws.

Notwithstanding this, Santos GLNG does not have large undeveloped, uncontracted reserves in Queensland.

For Santos, **forward term LNG prices are not relevant at all to long-term domestic gas contract offers which are predominantly influenced by the cost and risk of supply** (drilling new wells, new field development, processing and pipeline infrastructure costs). Other influences include the cost of terms and conditions that customers might require.

Santos has very limited uncontracted gas reserves on the east coast and, following Board approval, made long-term contract offers to customers that were based on contingent resources. These contingent resources carry much higher risk and must be converted to reserves through ongoing drilling and appraisal programs over the life of the contracts.

LNG plant and liquefaction costs

There is no evidence to support claims that domestic gas customers are paying for the cost of LNG investments that they don't use or require. Santos GLNG makes gas marketing decisions for uncontracted gas based on short run marginal costs. A return on historical sunk capital is not a factor in uncontracted gas pricing or gas destination decisions. More than 99% of our LNG plant operating expenditure is fixed (excluding fuel gas which is accounted for in the ACCC LNG Netback Price Series). There is negligible incremental LNG plant or liquefaction cost for an additional LNG cargo to be liquefied and therefore this does not affect the indifference point for LNG producers between the domestic gas market and the LNG spot market.

Summary

Based on analysis of market data, Santos considers that the JKM remains the best reference price for the ACCC's LNG Netback Price Series and the methodology remains appropriate to achieve the goal of greater price transparency for domestic market participants on the east coast. Any influence of the US Henry Hub or price markers in other countries on Asian spot LNG prices is already accounted for in the JKM.

The review of the LNG Netback Price Series appears to be based on the premise that east coast gas prices must be reduced. However, the claim that Australian east coast gas prices are not internationally competitive has not been substantiated and, based on Santos' analysis and experience in both the LNG and domestic markets, is untrue. Further it is incorrect that east coast gas users are paying for LNG plant and liquefaction that they don't require or use.

Any specific instances of anti-competitive behaviour or price gouging should be addressed using the lawful compliance and enforcement powers of the ACCC. Policy changes specifically engineered to reduce gas prices on the east coast run the very real risk of reducing investment in new gas supply and adversely impacting the small and mid-sized domestic gas producers who the ACCC says are needed in the market for supply diversity and competition. The influence on domestic gas prices of developing gas resources at scale, as has happened through the Queensland LNG industry, is also underestimated. Disincentivising LNG producers to invest in supply above their long-term LNG contract obligations would also adversely impact domestic gas supply and prices. The outcome would be the opposite of what is intended – less competition, less scale and liquidity, higher unit costs and higher prices, with increased reliance on imported LNG and diminished energy security.

The very perception that the federal government may intervene in the east coast gas market to reduce prices is influencing gas user behaviour, exacerbating the lack of willingness to support new gas developments which would increase supply diversity and competition, and put downward pressure on gas prices.

Santos would be pleased to provide further information or answer any questions you may have. Please contact Tracey Winters at [redacted] or on [redacted].

Yours sincerely

[redacted]

Kevin Gallagher
Managing Director and Chief Executive Officer