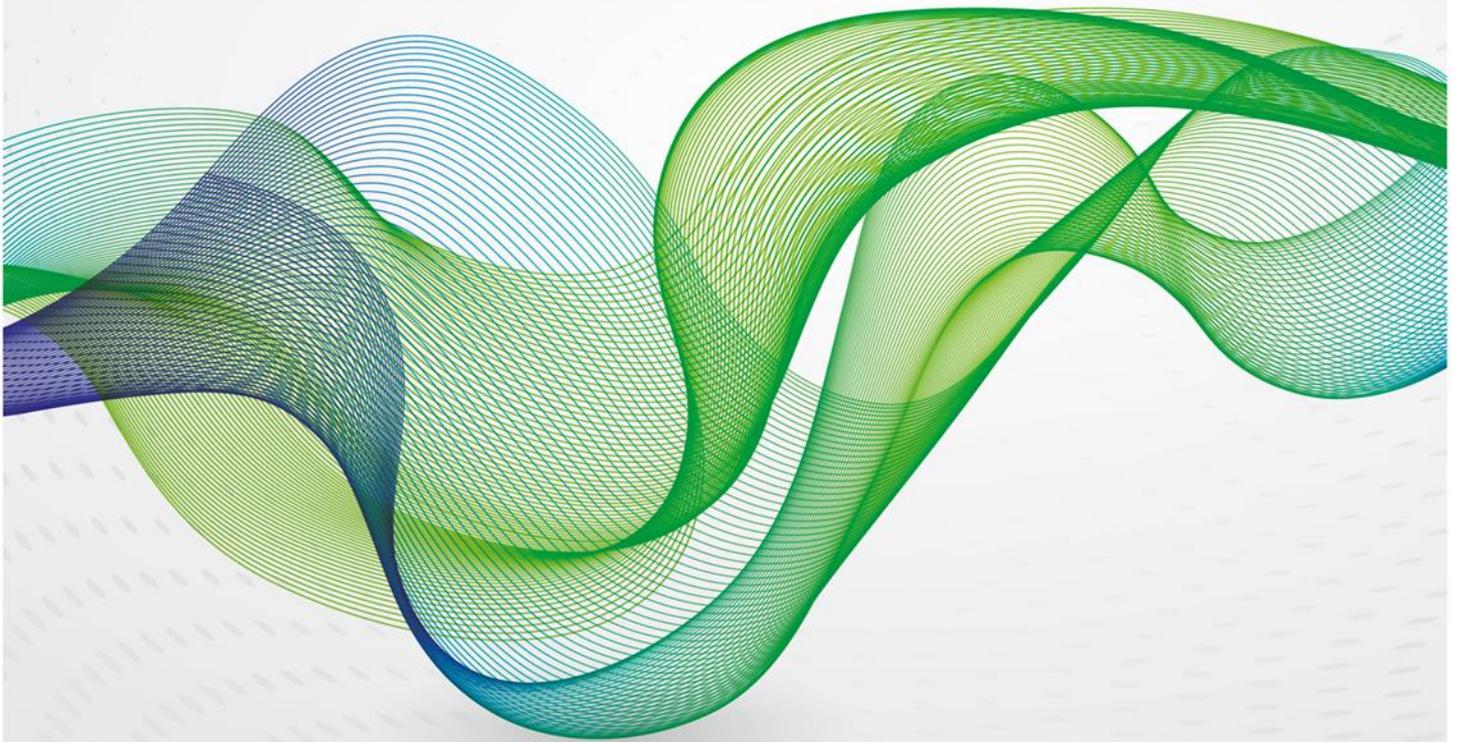


February 2021

Asia LNG Price Spike: Perfect Storm or Structural Failure?



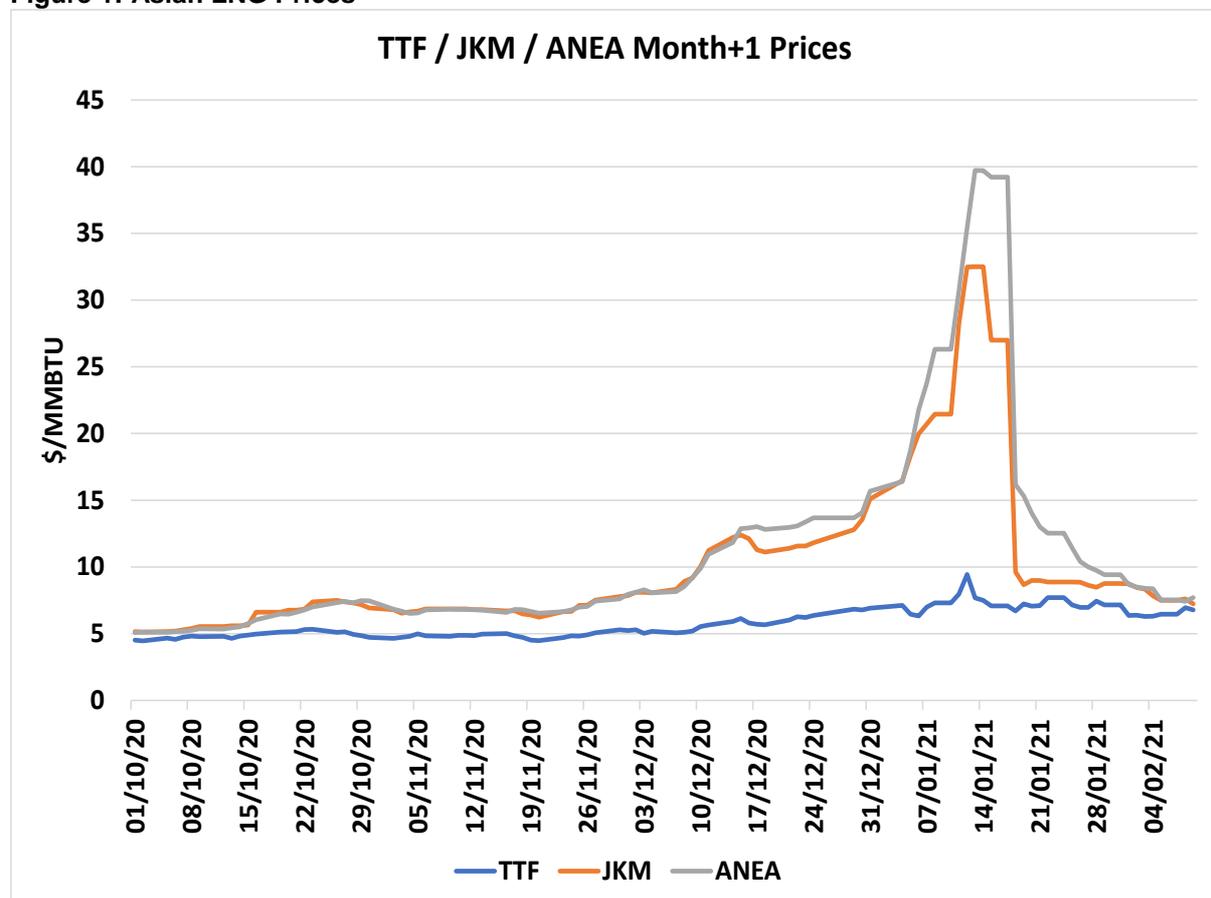
Introduction

In the middle of January, Asian LNG prices – by whatever measure is used¹ – leapt to over \$30/MMBtu. The combination of very cold weather in Northeast Asia and supply issues at some export plants together with a seeming lack of spare LNG tanker capacity, led to the conclusion that a perfect storm had hit the LNG market. However, other factors were also at play – in particular there were some structural market and infrastructure issues which also accounted for the very high prices, which did not exist, for example, in the North American or European markets meaning prices would not have spiked so much if there was a similar ‘perfect storm’. This note will consider all the factors impacting on Asian LNG prices and what some of the consequences might be on pricing and contracting for LNG in the Asian market.

The LNG Price Spike

The surge in prices began in December, with both JKM and ANEA rising above \$10/MMBtu. Prices reached \$20/MMBtu in early January and over \$30/MMBtu in mid-January.

Figure 1: Asian LNG Prices



Sources: S&P Global Platts, Argus Media

The TTF price is also shown and it can be seen that there was no similar upsurge in TTF prices, despite LNG supply being diverted to Asia (see below).

¹ In this note reference will be made to JKM (S&P Global Platts) and ANEA (Argus)

The prices shown are daily prices but they are not the prices for delivery on the day in question or even the next day (day ahead). The quotes or assessments are in respect of delivery of gas or LNG in a future month. For TTF the quote is for Month+1 (also referred to as 'Front Month'), so the December price quotes would all be for delivery of gas in January at TTF on an even daily flow during the month. JKM and ANEA are somewhat different and also for different time periods, as follows:

- ANEA is a similar Month+1 but the quotes are for LNG cargoes delivered to Northeast Asia (Japan, Korea, China, and Taiwan) but not for even delivery through the month. Instead, the price quotes are for single LNG cargoes delivered ex-ship (DES). ANEA quotes are similar to TTF but they are for half months, so the first half of December (through to the 15th) is for the first half of January, and the rest of December for the second half of January.
- JKM is different again with the quotes for delivery in January being from November 16th to December 15th. Therefore, the prices from mid-November to mid-December were for January delivery, the prices from mid-December to mid-January were for February delivery, and the prices from mid-January to mid-February for March delivery.

For much of the last quarter of 2020, JKM and ANEA prices were largely the same, despite effectively being for different periods. The divergence coincided with the price surge. Specifically, the final JKM price (on January 15th) for February delivery closed at \$27/MMBtu, before falling to \$9.63/MMBtu (on January 18th) for March delivery. Likewise, the ANEA price on January 15th (for delivery in the first half of February) closed at \$39.22/MMBtu, before falling to \$16.17/MMBtu on January 18th (for delivery in the second half of February). It is noticeable that since the beginning of February, JKM and ANEA have converged again as the market has stabilized, and the market perception of demand outstripping available supply has relaxed somewhat.

The TTF series is only for the Month+1 period, which is the single largest traded contract, both physical and futures, in volume terms. However, there are many other TTF contracts traded, whether for longer durations such as quarters, seasons or years, as well as shorter term covering within-month, weeks, day-ahead and within day, plus the daily balancing market. This has been well documented by Patrick Heather in his regular reports on European Traded Hubs.²

The situation for LNG in Asia is very different. While there are price quotes for several months and for the JKM futures market around three years, there is no real short term within-month quotes or assessments and certainly not the equivalent of a day-ahead price, which is popular in Europe. However, the latest METI LNG prices for January³ had a price for spot volumes contracted in January (presumably for delivery largely in February) at \$18.50/MMBtu, while the price for spot volumes arriving in January was \$15.50/MMBtu. Usually, arrival prices in a given month are close to the contract prices of the previous month – market participants sign contracts, and the cargo arrives the following month. But in January, the arrival price was more than double the December contract price, which suggests that urgent spot volumes were being purchased at very short notice (and very high prices) in the first half of January, for delivery in the same month. This dragged the January arrival price up way beyond the December contract price, which at \$7.40/MMBtu was less than half the January arrival price.

This raises the question of what the very high prices for ANEA and JKM in the first half of January actually represented. Ostensibly, they were supposed to reflect February deliveries, but given the evidence from the METI quotes, it would appear that the prices being assessed and/or reported, reflected, in part, very prompt cargoes for January delivery.⁴ We will return to this issue later.

² <https://www.oxfordenergy.org/publications/european-traded-gas-hubs-a-decade-of-change/>; Table 1, p.3

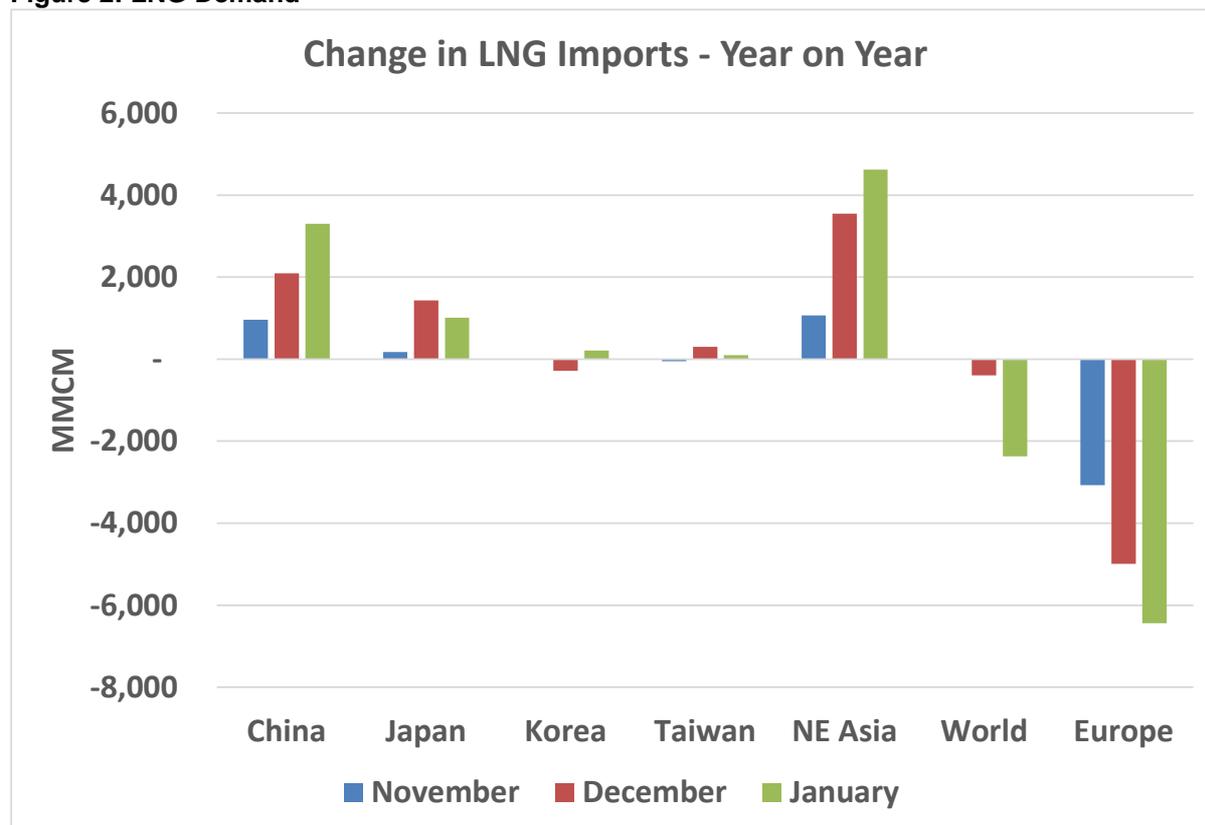
³ <https://www.meti.go.jp/english/statistics/sho/slng/index.html>

⁴ There may also have been a "panic" factor as well, with participants fearing that if the market is this short in January, following months could be worse, creating an incentive to buy early for February.

LNG Demand and Supply

The very cold weather in the Northeast Asia markets led to a rise in LNG demand. The figure below shows the year-on-year change in LNG imports for the Asian markets, the World total and Europe, for the last three months. The rising LNG demand in Northeast Asia can be seen, increasing as we moved into 2021, with the weather getting colder. China and Japan largely drove the increase, with a total year-on-year change in January of some 4.6 bcm. Globally, LNG imports were down, especially in January by some 2.4 bcm. Europe provided the required balancing item, with a 6.4 bcm decline.

Figure 2: LNG Demand



Source: S&P Global Platts

The decline in global imports in January 2021 compared to the previous year reflected a number of issues at export plants including Gorgon, Wheatstone, and Prelude FLNG in Australia, the shutdown of the Hammerfest plant in Norway as a result of an earlier fire and lower Qatar volumes in December as a result of extended maintenance. Overall, export capacity was expected to be around three per cent higher in January 2021 than in January 2020, but the issues at the export plants constrained capacity as demand rose.

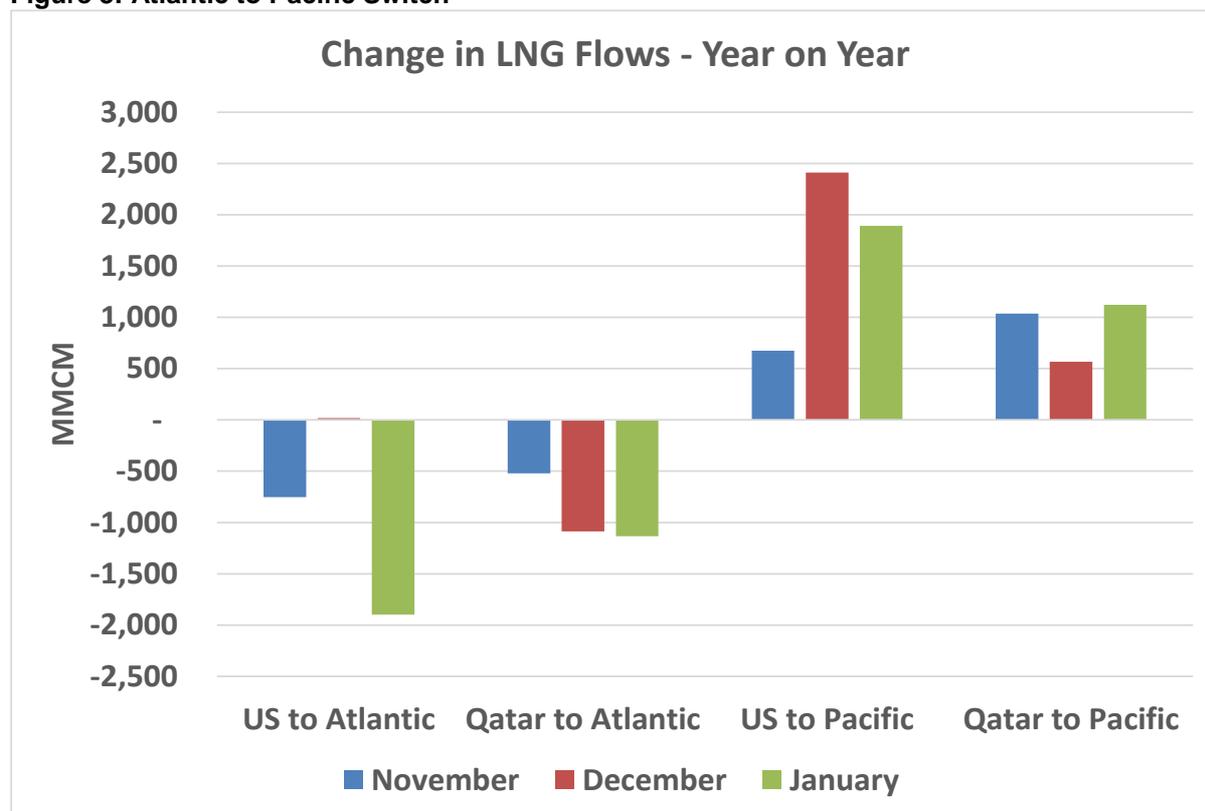
The switch of volumes away from Europe to Asia was reflected in the relative Atlantic and Pacific deliveries from both the US and Qatar. This was particularly noticeable in January with around 2 bcm switching from the Atlantic to the Pacific from the US – just over 20 cargoes – and some 1 bcm of Qatari volumes switching (10 cargoes or fewer as Qatar uses bigger tankers).

This is not just an issue of switching LNG from one basin to another, but it also results in an effective reduction in shipping capacity. US LNG heading to Northwest Europe - either the UK or Netherlands - has a round-trip time of some 25 days,⁵ while US LNG heading to Japan, via the Panama Canal and

⁵ Ship speed of 20 knots

assuming no congestion delays, has a round-trip time of some 44 days at the same speed. Delivering 2 bcm to Europe in January – assuming it is shipped as 20 cargoes – would require some 16 tankers, while delivering the same 2 bcm from the US to Japan would require some 28 tankers – an increase of 75 per cent – or a 42.5 per cent effective reduction in capacity.⁶ This was further compounded by the inability of the Panama Canal to take the extra cargoes with the result that some cargoes went around Cape Horn, while a significant number went via the Suez Canal – in effect cargoes that were already heading to Europe but which just carried straight on. US cargoes going to Japan via the Suez Canal would take some 70 days, requiring some 45 tankers – an effective 65 per cent reduction in capacity.

Figure 3: Atlantic to Pacific Switch



Source: S&P Global Platts

In January 2020 some 25 cargoes went from the US to the Far East, almost all via the Panama Canal, while in January 2021 some 48 cargoes went to the Far East, half of which went via the Suez Canal.⁷

In respect of Qatar, the round-trip time to the UK or Netherlands and to Japan is broadly the same so does not result in any reduction in effective capacity.

Impact on Europe

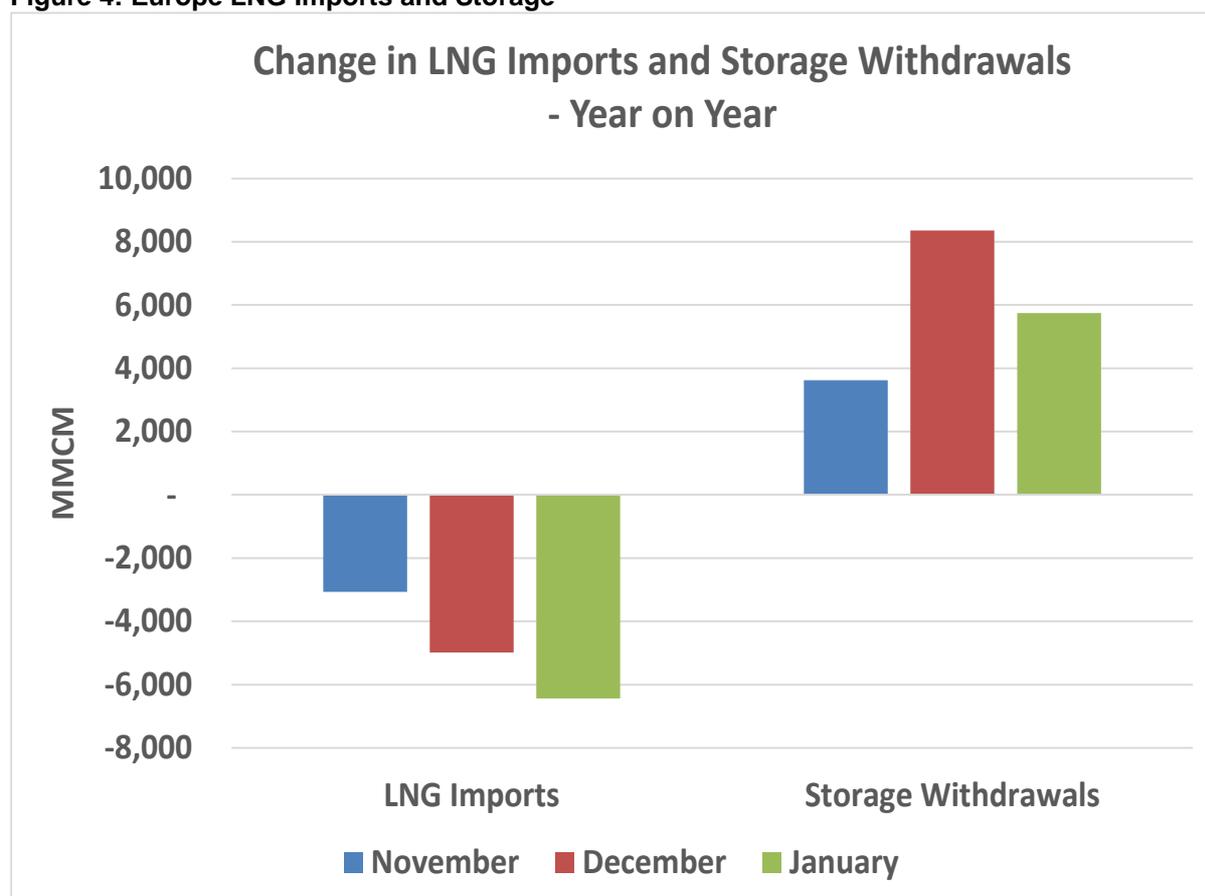
Over the November to January period, Europe LNG imports were some 14.5 bcm lower than in the same period for the previous year. European consumption was thought to be broadly at similar levels, while production may have been a little lower. With less available supply from LNG imports, there was a sharp increase in storage withdrawals, compared to the previous year. An extra 17.7 bcm was withdrawn from storage in the most recent November to January period compared to the previous year,

⁶ 16 tankers is 25 days divided by 31 days times 20 cargoes while 28 tankers is 44 days divided by 31 days times 20 cargoes

⁷ Source: Kpler

slightly larger than the decline in LNG imports. Gazprom has reportedly been withdrawing some volumes from storage to satisfy demand in Northwest Europe as Nord Stream and the Yamal-Europe pipeline have been running at effectively full capacity since early December. In Central Europe, Russian deliveries to Slovakia and Hungary via Ukraine dropped sharply as Gazprom's pre-booked annual capacity fell, and Gazprom chose not to book additional short-term capacity⁸. Effectively, it could be argued that European storage has satisfied Asian demand for LNG.

Figure 4: Europe LNG Imports and Storage



Source: S&P Global Platts, ENTSOG

Asian Infrastructure

Gas storage in Europe has been key in balancing both the European gas market and indirectly the global LNG market. The Asian markets effectively lack any significant gas storage: the LNG importers of Japan, Korea and Taiwan have no real storage apart from the tanks at the LNG terminals. The amount of LNG that can be kept in these tanks is limited and only lasts a few days from full to empty in an emergency. The LNG tanks have more similarities to linepack in a gas pipeline than storage from depleted fields, salt caverns or aquifers.

China has some gas storage, thought to be around 10-13 bcm of working capacity, but there are plans to increase it to 40 bcm by 2030. This currently represents around 4 per cent of Chinese gas consumption, compared to Europe where the gas storage capacity of over 100 bcm is 20 per cent of European gas consumption.

⁸ See data on daily gas flows at Greifswald (Nord Stream), Kondratki (Yamal-Europe), Uzhgorod (Ukraine-Slovakia) and VIP Bereg (Ukraine-Hungary) at: <https://transparency.entsog.eu/>



LNG Trading

In January, both China and Japan each imported over 11 bcm of LNG. In terms of contracted LNG,⁹ China has a total Annual Contract Quantity (ACQ) of around 80 bcm, which if spread equally would amount to under 7 bcm a month. Japan has a total ACQ of some 120 bcm or 10 bcm a month. There may well be some swing in the contracts to allow more cargoes to be taken in any given month, but the numbers suggest that there was significant demand for uncontracted LNG in the November to January period. Australia is a significant supplier to both markets and with some of their export terminals having constraints then they may not have been able to supply the contracted volumes from those terminals, possibly supplementing the contracts by buying spot cargoes – directly competing with Chinese and Japanese buyers. With the sudden surge in demand because of the cold weather and the supply constraints, this left buyers with what were effectively uncovered short positions for prompt delivery and their attempts to purchase short-term spot cargoes drove the LNG price up sharply.

The main problem is the lack of a liquid physical trading market in LNG either on a prompt basis or even month ahead. In contrast, TTF is an extremely liquid trading hub. In 2019 just looking at OTC (over the counter) physical trades, these totalled some 8,000 TWh just for Month contracts,¹⁰ the vast majority of which were the Month+1 contract. This is equivalent to some 750 bcm, which is one and half times the total annual European gas consumption and just under three times the annual Northwest European¹¹ gas consumption, the main area served by TTF and NBP. To this 8,000 TWh can be added OTC Month contracts for NBP (1,529 TWh) plus exchange traded Month contracts for TTF (5,300 TWh) and NBP (4,600 TWh). This totals over 1,800 bcm just for the Month contracts – seven times the annual Northwest European gas consumption. In addition, the daily contracts are also very liquid and can balance the final flows on the day.

It helps that effectively these trades allow for instantaneous delivery on-the-day within the pipeline systems, which is not available for LNG cargoes in Asia or anywhere else. However, the very existence of this very liquid market enables buyers, sellers, and traders to balance most of their portfolio in advance of the month of delivery and then use the flexibility within the month to finally balance on-the-day. The liquid physical trading market acts as a buyer and/or seller of last resort.

There is nothing remotely like this physical trading market in LNG in Asia, which would allow cargoes to be bought and sold for Month+1 and then trade prompt within the Month. JKM futures liquidity has grown significantly over the past few years, with total 2020 cleared volumes increasing by 50 per cent to 830,000 lots (this is around 230 bcm equating to around half the annual consumption of China, Japan, Korea, and Taiwan). However, this is not a physical market and is only really useful for hedging. It cannot get you a spot cargo at short notice when you need it or allow you to offload a surplus cargo if it is not needed. In theory, it would have been possible to hedge on the JKM futures in November or December for the February delivery month and lock in a price, but the very act of multiple participants looking to buy the February contract would itself have impacted the futures price – by how much though would have depended on the liquidity of the market.¹²

As noted above, ostensibly the JKM and ANEA price assessments and benchmarks are for Month+1 delivery – with slightly different time periods for assessment – and there is no real within-month market assessment for very prompt delivery of cargoes. From looking at the first half of January price assessments for both JKM and ANEA, the high prices may well have been more reflective of the immediate delivery of LNG in January rather than for February delivery, which seems to be borne out by both the METI LNG Contract (\$18.50/MMBtu) and Arrival (\$15.50/MMBtu) prices for January. This

⁹ Source: Nexant World Gas Model, GIIGNL

¹⁰ Source: Data collated and analysed by Patrick Heather

¹¹ UK, Ireland, Denmark, Germany, Belgium, Netherlands, Luxembourg, and France

¹² Open interest on JKM futures at the end of December was around 100,000 lots (each lot is 10,000 MMBtu). Typically, some 8 to 10 per cent would have been for the first month – in this case the February contract – and 5 to 7 per cent for the following month. A cargo of LNG is approximately 350 lots (170,000 cm tanker), so 10,000 lots is equivalent to 28 cargoes. Trying to buy 2 or 3 cargoes to hedge a position would be likely to have a significant impact on the price.

implies that the LNG market may need to look for different price assessments for different time periods of delivery (especially for more prompt delivery), rather than having basic monthly assessments, although the lack of enough potential trades and flexibility of supply, close to the LNG delivery point, represent significant obstacles.

Following the price spike, an analysis by the IEA¹³ discussed the need to create more market resilience. It emphasised the need for more short-term natural gas trading in Asian markets to help establish market-driven competitive pricing mechanisms. It was noted that this would require more policy reforms....“regulatory policies need to guarantee open and transparent access to gas infrastructures.....ensuring the independence of infrastructure operators from supply incumbents, such as the incorporation of PipeChina in 2020, is another prerequisite. Competitive and transparent market rules provide a framework for stability and reliability, and foster investment to meet additional demand needs.”¹⁴ Following these policies, which have been promoted for many years, might eventually lead to a more liquid trading market for gas and LNG in the Asian region. However, governments in these countries have to be convinced that the only way to avoid expensive price spikes is to liberalise and, so far, they either do not regard this as a high priority or they fear it will lead to unwanted consequences in their energy markets and to their national energy champions.

These concerns are not necessarily going to lead to a sudden resurgence in long-term oil indexed contracts, but the market may need to look for “short-term, flexible contracts, which can vary from a few months to a few years and be priced against different benchmarks.”¹⁵ Henry Hub pricing is already widely used in US LNG export contracts, but participants might also look at TTF or NBP pricing – with a basis differential – as alternatives, in the absence of more reliable Asian LNG benchmarks. It may also promote more localised specific China or specific Japan pricing, for example, in the longer term, if and when market reforms have been implemented.

Conclusions

It does seem clear that the LNG market in Asia, if not hit by a perfect storm, was hit by one or more fierce hurricanes. The combination of very cold weather increasing demand, supply issues at a number of export plants, contracts running at maximum take, and the need to divert large volumes of cargoes from the Atlantic to the Pacific basins – principally US and Qatar cargoes – leading to constraints on shipping, all combined and resulted in a sharp increase in prices in a very illiquid market.

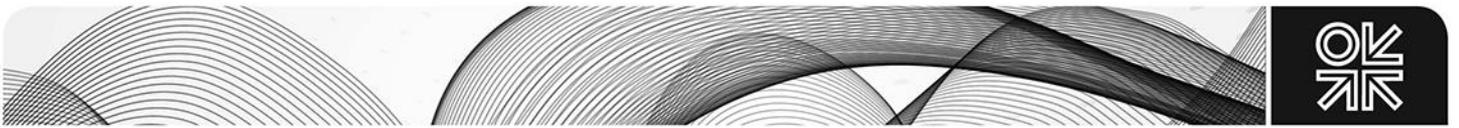
However, that is not the whole story. The price spike, in some respects, may have been an accident waiting to happen. The lack of any meaningful gas storage in the region, especially in a country like Japan, which is almost totally dependent on LNG, means the market does not have the back-up flexibility that Europe has. This is compounded in Japan by the nature of its fragmented market with few pipeline interconnections between the main cities and regions. The LNG tanks at the regas terminals act as little more than glorified linepack and gas cannot be moved easily from one part of Japan to another. For example, a shortage of gas in Tokyo (on Honshu island) could not be overcome by having surplus supply on one of the other Japanese islands, or even in Osaka, because there are no pipeline interconnections.

The other missing piece in Asia is the lack of a liquid physical trading market, as operates in Europe and North America. A liquid physical trading market allows participants to manage their portfolio of gas for different time periods whether for season, months (especially the Month+1) or within month, particularly day-ahead. The LNG market, by its nature, may struggle to replicate this, but the Chinese market has many similarities to the European market in terms of diversity of supply so has some of the requirements for physical trading to develop. More interconnection of markets in Japan could also allow

¹³ <https://www.iea.org/commentaries/asia-s-record-gas-prices-underline-the-need-to-make-its-markets-more-resilient>

¹⁴ <https://www.iea.org/commentaries/asia-s-record-gas-prices-underline-the-need-to-make-its-markets-more-resilient>

¹⁵ <https://www.reuters.com/article/idUSKBN29U0ZR>



trading to develop. Both of these, however, require the appropriate policies to properly open up the markets.

The price spike may also have implications for the possible use of benchmarks such as JKM or ANEA, in contracts, whether short, medium or even long-term. While this may not herald the revival of long-term oil indexed contracts, the use of other benchmarks, less subject to price volatility from an illiquid physical market, may become more attractive. This still won't stop prices rising in a cold winter but it would prevent prices rising to extremely high levels on the back of a very thin market and possibly impacting prices under contracts which are not for the same period as the price spike. Ultimately, however, the lesson from North America and Europe is essentially that there is no option other than a deep and liquid hub market where risks can be hedged, combined with additional infrastructure, especially short-term storage.