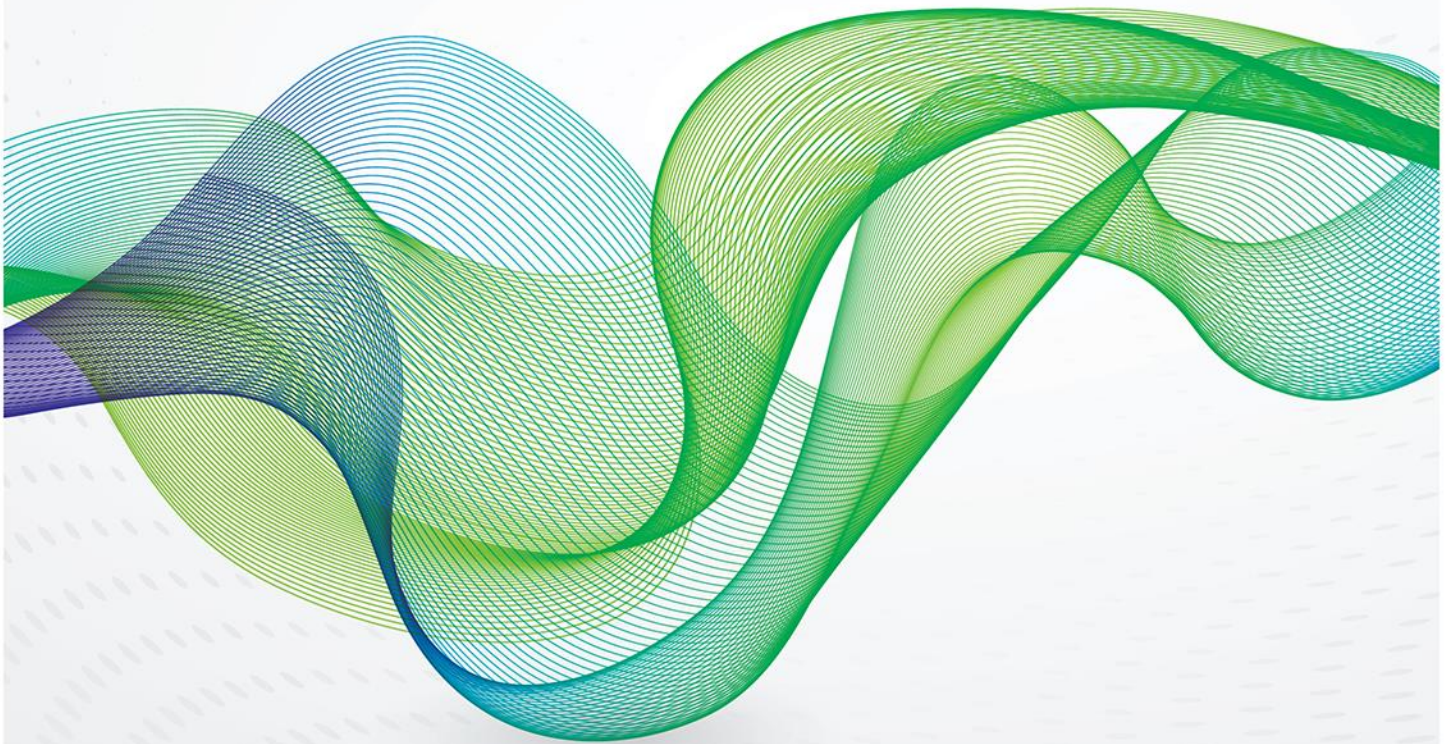


JUNE 2020

\$2 Gas in Europe (Part III): Down, Down, Deeper and Down





Expect the unexpected seems to be an appropriate quote for the current situation in the European gas market, which has been badly hit by the COVID-19 pandemic. Back in October 2019, the Oxford Institute for Energy Studies (OIES) published an Energy Comment¹ which considered the possibility of \$2 gas in Europe during 2020. By \$2 gas it was meant that, at least the average monthly price for TTF or NBP would be below \$3 i.e. start with \$2 at the beginning (\$3 gas is broadly equivalent to €9/MWh and \$2 gas to €6/MWh). The Comment was prompted by the filling of European gas storage to historically high utilisation levels by early October 2019, and the possibility of a mild winter coupled with a deal on Ukraine transit, leading to gas in storage in Europe at the start of the injection period in April 2020, still at relatively high levels. When combined with a further ten per cent increase in LNG supply between 2019 and 2020 and weaker demand in the key Asian markets, the Americas and Middle East for LNG imports, this would in all likelihood lead to \$2 gas in Europe in Q3 of 2020.

The mild winter and a deal on transit in Ukraine happened and by the time we reached the end of February 2020, \$2 gas had arrived much earlier than thought, with the month-ahead index for March for TTF closing at \$2.91/MMBtu and for NBP at \$2.88/MMBtu.² Even Asian spot LNG prices dipped below \$3 with the ANEA (Argus Northeast Asia spot LNG) month ahead price for March averaging \$2.92/MMBtu.³ All this was happening before the real impacts of COVID-19 were felt in the global gas markets, other than in China. These developments prompted OIES to publish a follow up Energy Comment⁴, which asked the question where all the rapidly rising LNG supply would now go, in the face of collapsing demand. Not all suppliers, whether LNG suppliers, pipeline exporters to Europe or indigenous producers such as Norway, could possibly achieve the same levels as in 2019, especially in the summer months, and as storage fills. The question asked, therefore, was – who will blink first?

This third instalment on \$2 gas in Europe looks at the question who has blinked first and how much more supply needs to be taken off the market as the impact on demand of COVID-19 continues. Prices in Europe are already below \$2 with the month-ahead index for June for TTF closing at \$1.55/MMBtu and for NBP at \$1.42/MMBtu.⁵ The forward curves suggest price may barely get back above \$2 until we get to October 2020. While prices are already much lower, serious questions are being asked as to whether prices in Europe could go negative, especially if more supply is not shut in. Looking further ahead when might the gas markets, in Europe and around the world, begin to rebalance and what more information might we be able to get from analysing the gas storage balance in Europe? Could the projected gas storage balance in Europe provide some clues as to where prices might be heading?

The European Market in 2020

Latest 2020 Flows and Storage

Data on gas demand in Europe is often either patchy, with some countries not covered, and/or data not being available in a timely fashion. This is especially crucial in the context of the impact of COVID-19 on gas demand, which only began to have an effect from early or mid-March onwards. Our best estimate is that European gas consumption was some 5% down year-on-year in Q1 2020, only partly due to the COVID-19 impact but much more reflecting the relatively warm weather in January and February, reducing the heating demand. In order to understand much better what is happening in the market, more timely data is available on the supply side, whether it be production, pipeline imports or LNG imports. This is analysed below.

¹ Fulwood, M., 2019. Could we see \$2 gas in Europe in 2020? *Oxford Energy Comment*, October 2019. <https://www.oxfordenergy.org/publications/could-we-see-2-gas-in-europe-in-2020/>

² Source: Argus Direct. The month-ahead index is the average daily midpoint price for March deliveries during February.

³ Source: Argus Direct.

⁴ Fulwood, M., 2020. \$2 gas in Europe is here: who will blink first? *Oxford Energy Comment*, March 2020. <https://www.oxfordenergy.org/publications/2-gas-in-europe-is-here-who-will-blink-first/>

⁵ Source: Argus Direct. The month-ahead index is the average daily midpoint price for June deliveries during May.

The analysis of European gas supply in the first five months of 2020 can be broken down into two parts: “Before Lockdown” (BL) from the beginning of January to mid-March, and “After Lockdown” (AL) from mid-March to the end of May.

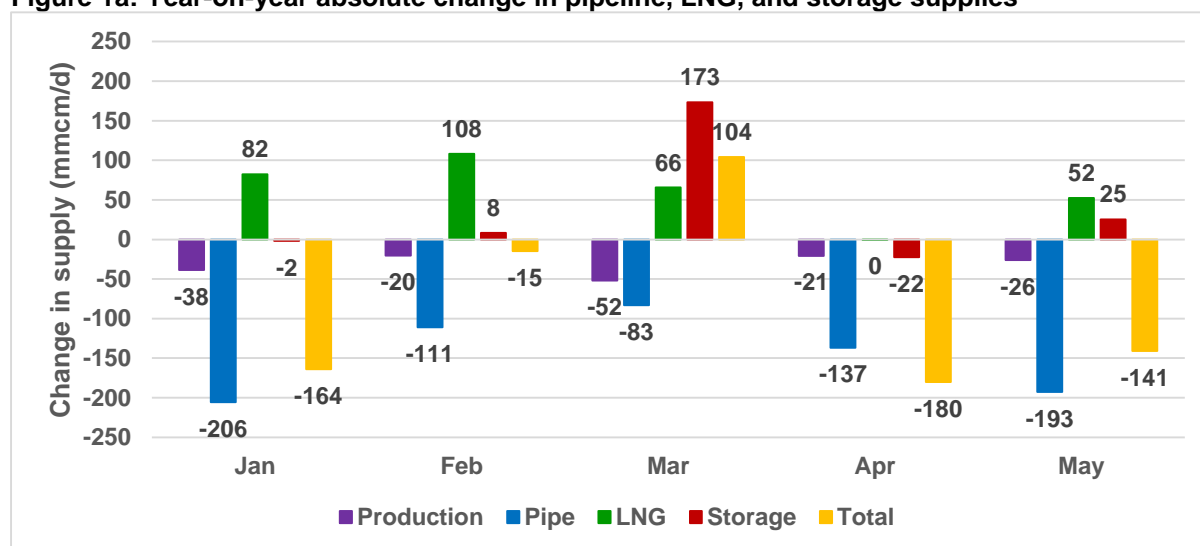
European gas production, in total continued to decline, both in BL and AL. For the period January to May as a whole, it was down by 12% year-on-year, consistently across all five months.

Storage withdrawals in January and February were virtually unchanged from a year earlier, but in March ramped up to 4.5 times the net withdrawals seen in March 2019. However, the March figure is explained by the fact that net storage withdrawals in March 2019 were exceptionally small, at levels not seen since March 2012. Net storage withdrawals in March 2020 were substantially below those in years prior to 2019. Moving into the injection season, net injections were slightly higher in April and slightly lower in May than in 2019. So, for the period as a whole, the change in stocks between 1 January and 31 May 2020 equated to a net withdrawal of 16.3 bcm. This was more than in 2019 (principally because of the March figures), but significantly less than in the 2015 to 2018 period

Pipeline supplies remained relatively stable in January-April (720-774 mmcm/d) before falling slightly in May (687 mmcm/d). LNG supplies were also relatively stable across the first five months of 2020, growing gradually from 311 to 357 mmcm/d. The more dramatic picture emerges in the year-on-year comparison, which highlights the substantial decline in pipeline imports by 17% for the period as a whole. By contrast, LNG imports grew by 23% year-on-year. In the BL period, pipeline supplies eased back as Gazprom especially reduced flows as the new Ukraine transit deal was bedding down. In the AL period, it would seem that pipeline suppliers rather than LNG suppliers have borne the brunt of the decline in EU import demand.

In Figures 1a and 1b the total of all the changes in production, pipeline and LNG imports and storage changes, represents a good proxy for demand in Europe.⁶ April and May figures suggest declines of some 15%.

Figure 1a: Year-on-year absolute change in pipeline, LNG, and storage supplies⁷

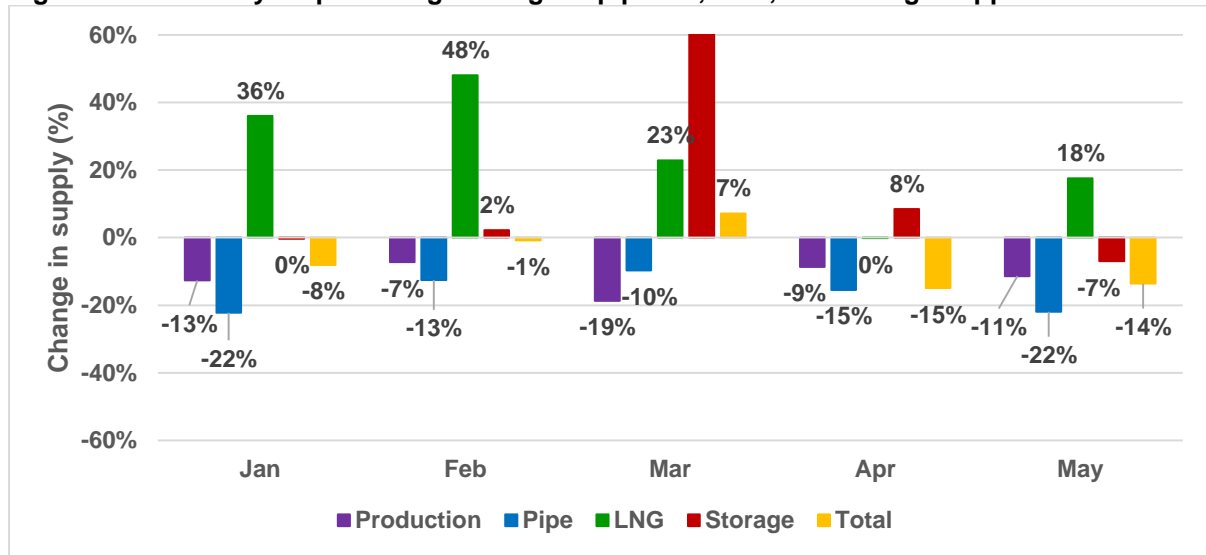


Source: Data from ENTSOG Transparency Platform (Production & Pipeline Supplies), Gas Infrastructure Europe (Storage), and Platts (LNG Supplies)

⁶ The only part missing is pipeline and LNG exports from Europe to other regions.

⁷ Norway is considered an ‘external’ pipeline supplier, along with Russia and Algeria, so is not included in production.

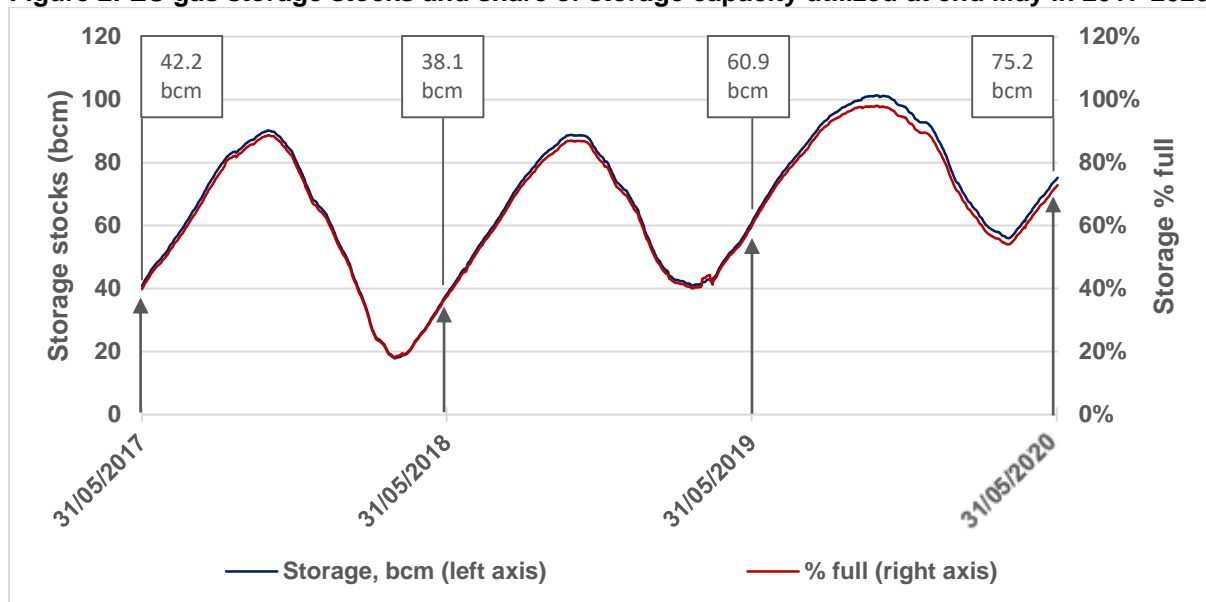
Figure 1b: Year-on-year percentage change in pipeline, LNG, and storage supplies



Source: Data from ENTSOG Transparency Platform (Production & Pipeline Supplies), Gas Infrastructure Europe (Storage), and Platts (LNG Supplies)

In the face of a year-on-year decline in demand that primarily affected pipeline imports, and continued overall growth in LNG supplies, the combination of lower-than-average net withdrawals in Q1 and higher-than-average net injections in April-May, with already high stocks at the end of 2019, resulted in European storage stocks at historically high levels for this time of year. Total storage stocks on the 31st of May 2020 were almost 25% higher than a year earlier, and almost double the 2018 level.

Figure 2: EU gas storage stocks and share of storage capacity utilized at end May in 2017-2020

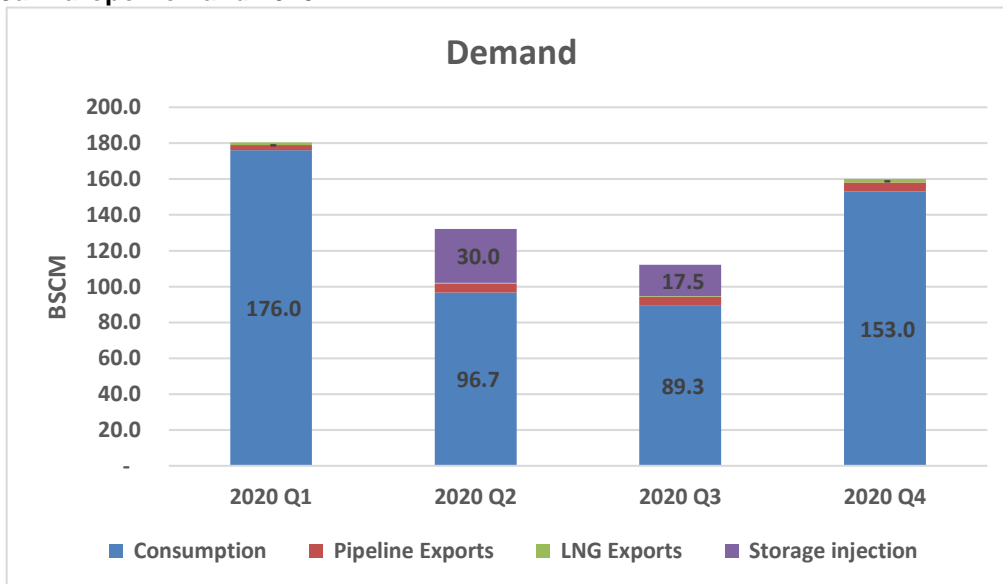


Source: Data from Gas Infrastructure Europe

European Balances in 2020

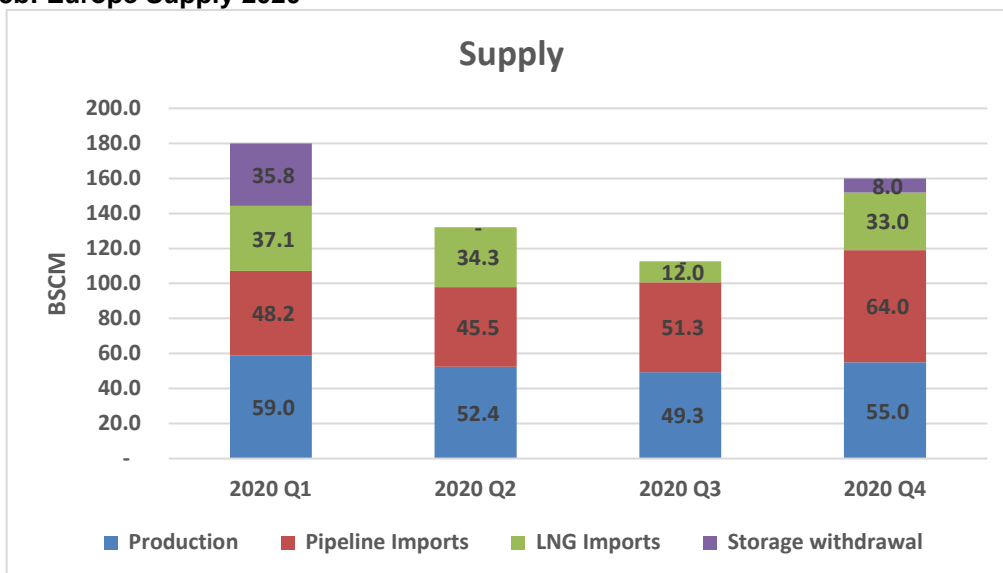
Given the surge in LNG imports, lower demand, lower pipeline imports with plenty of upside flexibility, and rapidly filling storage stocks, the key question is how the European market might balance in the remainder of 2020. The May OIES Quarterly Gas Review focused on the impact of COVID-19 on global gas markets.⁸ The Figures below have been updated from the Quarterly Review with the latest data. In Q1 consumption declined by some 10 bcm or 5% year-on-year. Production was down 5 bcm and pipeline imports down by 13 bcm. LNG imports, however, were up 10 bcm, with 35 bcm withdrawn from storage – more than in 2019 - all due to March withdrawals, because of the cold spell.

Figure 3a: Europe Demand 2020



Source: Data from the International Energy Agency, OIES Estimates, Nexant World Gas Model

Figure 3b: Europe Supply 2020



Source: Data from the International Energy Agency, OIES Estimates, Nexant World Gas Model

⁸ OIES, 2020. *Quarterly Gas Review: The impact of COVID-19 on global gas markets*. May 2020. <https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-9/>

The big fall in consumption occurs in Q2, down 13 bcm compared to 2019 Q2 – some 12% lower. Q3 consumption is 8 bcm down, year on year, around 8% lower, as there is some recovery in economic activity. However, the ability of Europe to absorb supply through injecting into storage continues in Q2, even though storage utilisation was much higher at the end of March 2020 than 2019 - the detail on storage is discussed further below. As a result, together with the decline in pipeline imports and indigenous production from Norway and the Netherlands, LNG can continue to come into Europe. It is in Q3 that supply overwhelms demand, with much less space left in storage, only 13 bcm of LNG imports can be accommodated.

LNG Balances in 2020

Given that the European market, with its extensive storage capacity and liquid traded market, generally acts as the 'balancing market' for global LNG trade, it is imperative to examine how the likely drop in European LNG imports in Q3 2020, associated with European storage facilities reaching full capacity will likely impact the global LNG balance in the remainder of 2020.

Total global LNG trade was at record levels in Q1 2020, and while there has been a small decline so far in Q2, the estimated Q2 total of 116 bcm (April and May actuals plus June forecast) is slightly higher than in Q2 2019. In the short-term, though, the ability of European storage to absorb the LNG, combined with a small recovery in China is sufficient to offset weakness elsewhere, especially in Japan, Korea and Taiwan. It is in Q3 2020 when the LNG market takes the biggest hit, with global LNG imports estimated at some 104 bcm, compared to 118 bcm in 2019, despite China and other regions taking more volumes – Europe simply has no more storage room left. In respect of exporters, the US, Russia, Australia, Indonesia and Malaysia are most affected, but all suppliers can expect to see lower volumes – apart from Qatar which emerges largely unscathed, as the low-cost producer. However, US LNG exports still increase by around 20 bcm compared to 2019 – a rise of just over 40%.

In the March 2020 Comment,⁹ the question was asked - who will blink first? It is clear that pipeline imports into Europe are significantly lower, principally from Russia, but also from Algeria. Norwegian flows are also lower in the first five months. This was illustrated by the year-on-year decline in European pipeline imports shown in Figures 1a and 1b. In terms of deliveries of LNG globally in Q2, there are signs of a slowdown, compared to Q1 2020 but not compared to last year. However, it has been reported that possibly 100 cargoes of LNG from the US have been cancelled for June and July liftings, which on average would be delivered to the markets around a month later, so would not all appear in the Q2 LNG imports figures.

Q3 LNG imports are expected to be some 14 bcm lower than in 2019. At the same time, LNG export capacity is increasing by 10% between 2019 and 2020, with Q3 2020 capacity some 14 bcm higher than the same period of 2019. Even if this capacity was only 70% utilised, this would add some 10 bcm to the 14 bcm of lower demand discussed earlier. A total of maybe 24 bcm of LNG would need to be shut in for delivery in Q3, which approximates to some 240 cargoes.¹⁰

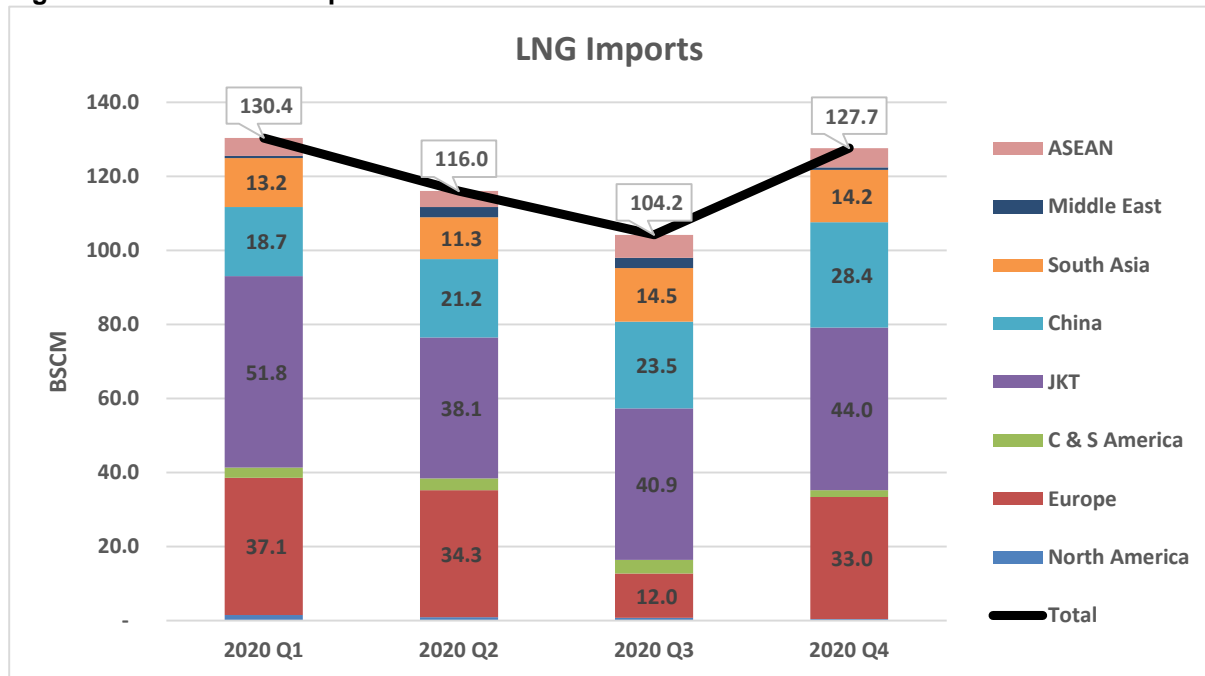
Outside the US it is less clear how many cargoes may, or may not, be lifted in the next two to three months. Qatar does not appear to be holding back,¹¹ with cargoes originally destined for Asia being diverted to Europe, especially the South Hook terminal in the UK. It might be expected that additional US cargoes scheduled for lifting in August (deliveries in September) will also be cancelled, but probably not enough to balance the market. Our modelling suggests that Australia, Russia, Indonesia and Malaysia would also be looking at much reduced flows. The number of LNG cargoes being shut in would most likely only be reduced if there were even deeper cuts in pipeline imports and production in Europe.

⁹ Fulwood, M., 2020. \$2 gas in Europe is here: who will blink first? *Oxford Energy Comment*, March 2020.

¹⁰ An LNG tanker of 160,000 cm to 170,000 cm of LNG delivers around 100 million cubic metres of regasified LNG

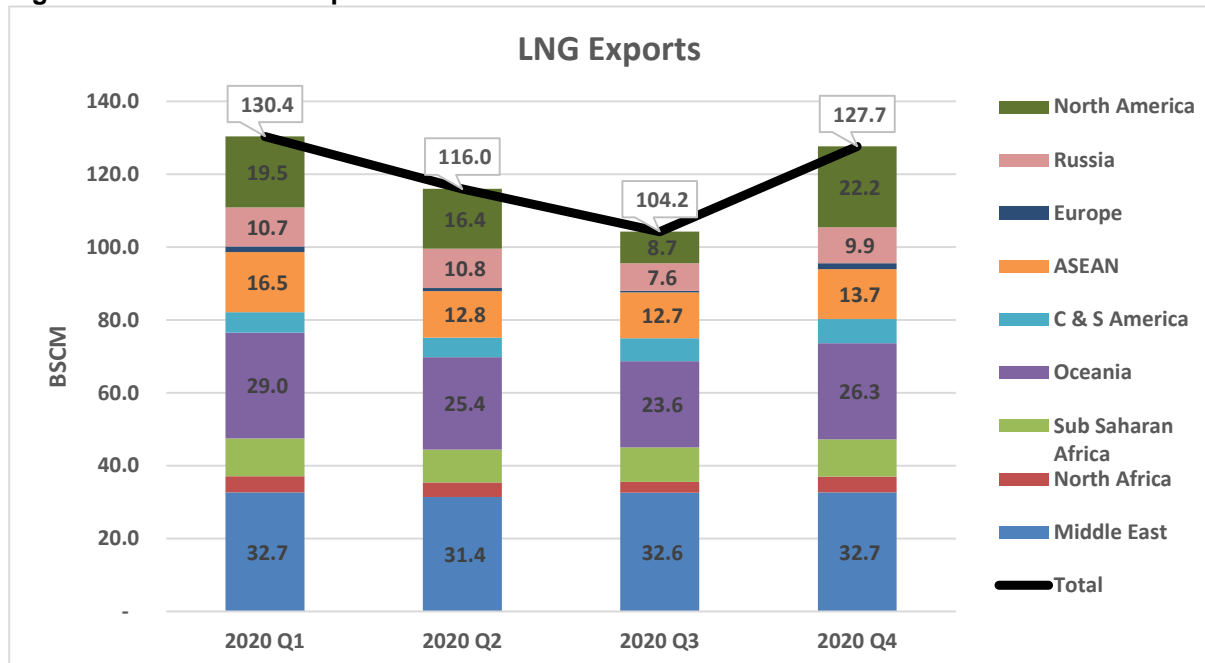
¹¹ Argus, 2020. Qatar will not cut LNG output. *Argus News*, 22 May. <https://www.argusmedia.com/en/news/2108004-qatar-will-not-cut-lng-output>

Figure 4a: Global LNG Imports 2020



Source: OIES estimates, IEA data, Platts LNG Service and Nexant World Gas Model

Figure 4b: Global LNG Exports 2020



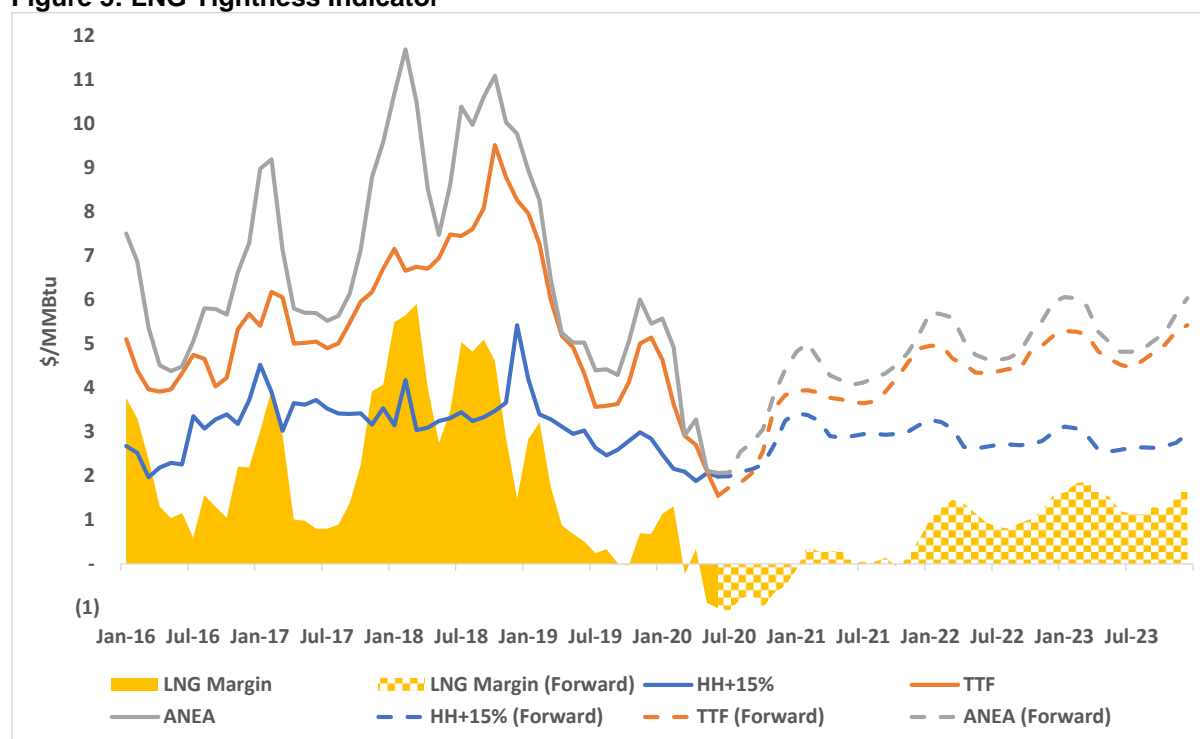
Source: OIES estimates, IEA data, Platts LNG Service and Nexant World Gas Model

LNG Tightness Indicator

The oversupply highlighted in the LNG balances for 2020 is already evident in the OIES 'LNG Tightness Indicator', which is a proxy measure for the tightness of the global LNG market, and analyses the netback for US Gulf Coast LNG from the higher of either Asia or Europe spot prices. US LNG can be considered the marginal molecule in the global LNG market, not because it is necessarily the most expensive – oil-indexed contracts are still higher priced than the full cost of US LNG into the Asian markets for example – but because the contractual structure makes it much easier to shut in US cargoes than traditional take or pay LNG contracts.¹² The liability in the US LNG contracts is mostly limited to the liquefaction capacity fee and not the molecule of gas, while in the traditional contract the buyer is on the hook for the total delivered price (although, with make-up provisions, the cargo is often deferred and not lost, as is the case with US LNG).

Prices in both Europe and Asia have declined significantly in the last few months. The month ahead index for June for TTF closed at \$1.55/MMBtu and for NBP at \$1.42/MMBtu.¹³ The June ANEA¹⁴ closed at \$2.06/MMBtu. The forward curve for TTF has recently risen. It was below \$2 until October at the end of May, but in early June it strengthened to above \$2 for quotes at the end of Q3, while ANEA now averages \$2.50 for Q3.

Figure 5: LNG Tightness Indicator¹⁵



Source: OIES, based on data from Argus Media (Forward curve as of June 12th)

Figure 5 is based on data from Argus Media and shows the price for TTF in the Netherlands, the ANEA spot price in Asia and the Henry Hub price in the US. It then calculates the highest netback from Europe or Asia to the Gulf of Mexico based on the relevant transport costs. The LNG Tightness calculation is shown on a historical basis and for futures prices, and provides an indication of whether developers in

¹² This does not necessarily apply to all US LNG cargoes as many of them may have been pre-sold at higher prices.

¹³ Source: Argus Direct. The month-ahead index is the average daily midpoint price for June deliveries during May.

¹⁴ Source: Argus Direct. Argus Northeast Asia spot LNG price

¹⁵ The calculation of the LNG Tightness Indicator has been amended to add a 15% uplift to Henry Hub to reflect the full commodity cost the LNG as in the Cheniere contracts.

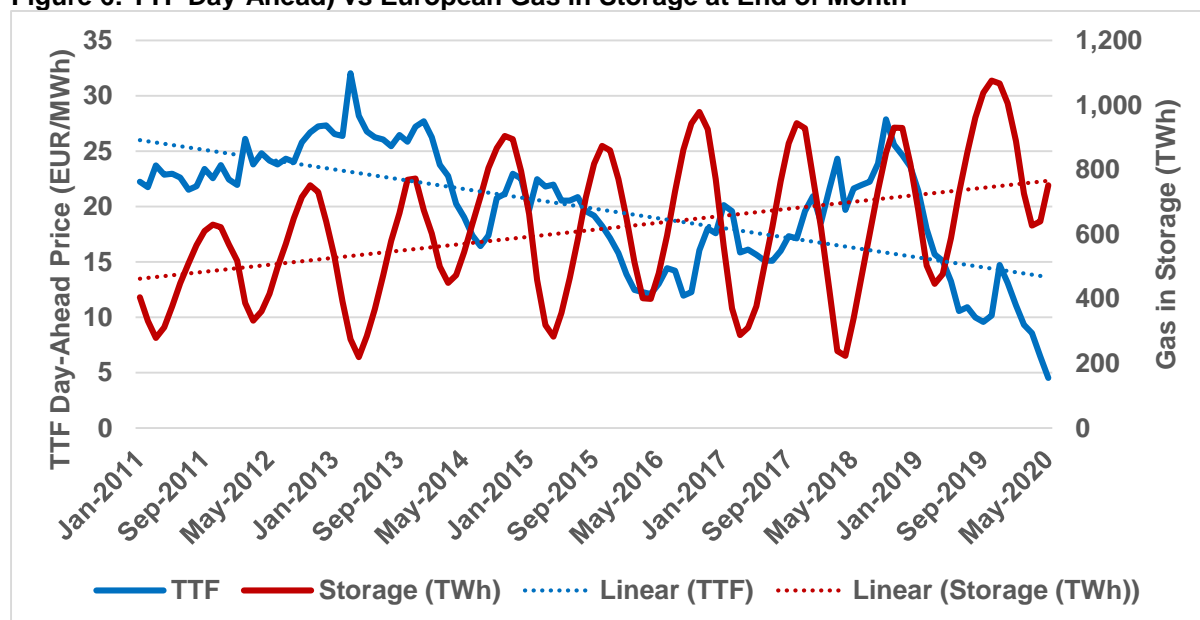
the US can expect to recover the cost of liquefaction on the Gulf Coast (which is generally estimated at around \$3/MMBtu based on the traditional Cheniere contract).

The LNG margin turned negative in March and almost all the netbacks through to the end of this year, remain negative, before turning slightly positive in 2021. This means that the full shipping costs are not being covered in LNG deliveries for the rest of 2020. For June through October this year the average negative margin is just under \$1, but this is the margin from Northeast Asia. The negative margin from TTF is some \$0.40 more than from Japan, and the negative margin from NBP is even larger, as NBP prices have been consistently below TTF since February 2020. The UK is importing substantially more LNG than other Northwest Europe terminals – in April and May almost 4.5 bcm, which is more than Netherlands and Belgium combined. Much of this LNG is being effectively re-exported through the BBL and IUK interconnectors to the rest of Europe, with some going into UK storage. In the month of May the UK exported more gas to Europe than was consumed in gas-fired power stations, and in the last week of May the exports even exceeded the volumes consumed in the local distribution zones.¹⁶

European Storage and Prices

European storage has played an important role in the analysis of the global market, especially the LNG market, over the past year or so, but could it also provide a more direct guide to where prices might go? As gas storage stocks have grown year-on-year, the long-term trend is for European hub gas prices to fall, as illustrated by Figure 6. The amount of gas held in storage has been increasing consistently since 2011, once the seasonal movements are taken out. This has been partly due to the growth in storage capacity from 57 bcm in January 2011 to 103 bcm in May 2020 but also, in the last two years, because of much higher utilisation. Over a similar period, the monthly average day-ahead price on TTF declined by almost 40% between May 2018 and May 2019. Then, between May 2019 and May 2020, the price declined by a further 63%.

Figure 6: TTF Day-Ahead) vs European Gas in Storage at End of Month



Source: Data from Argus Media (price) and Gas Infrastructure Europe (storage)

¹⁶ Gridwatch, 2020. UK GAS NTS (National Transmission System). <https://gridwatch.co.uk/gas/mcm>

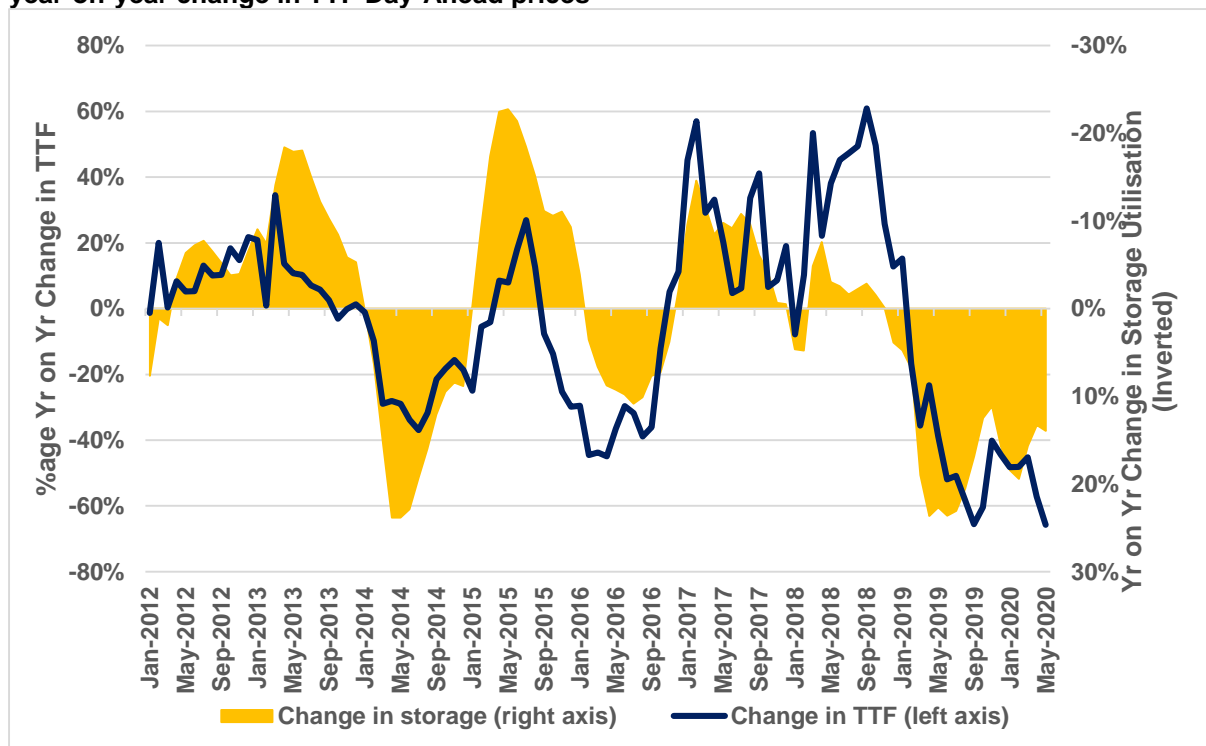
While these two trends are moving in opposite directions, the cycle of storage injections and withdrawals follows a fairly regular seasonal pattern. By contrast, prices are driven by supply and demand fundamentals that go beyond seasonal factors, hence there is a much less seasonal shape to the TTF price series in Figure 6.

However, when we remove the seasonal impact by measuring year-on-year changes in both TTF day-ahead prices and the share of storage capacity that is being utilised, we can more clearly see the correlation between the two.

This does not suggest that storage utilisation rates are directly impacting prices or vice-versa. Correlation does not imply causation. Rather, both storage utilisation and prices are impacted by the same fundamental forces of supply and demand. When the market is supply long, prices are generally lower and the excess supply is looking for a home which storage can provide. Conversely, when the market is supply short, gas prices are generally higher and storage can release more gas.

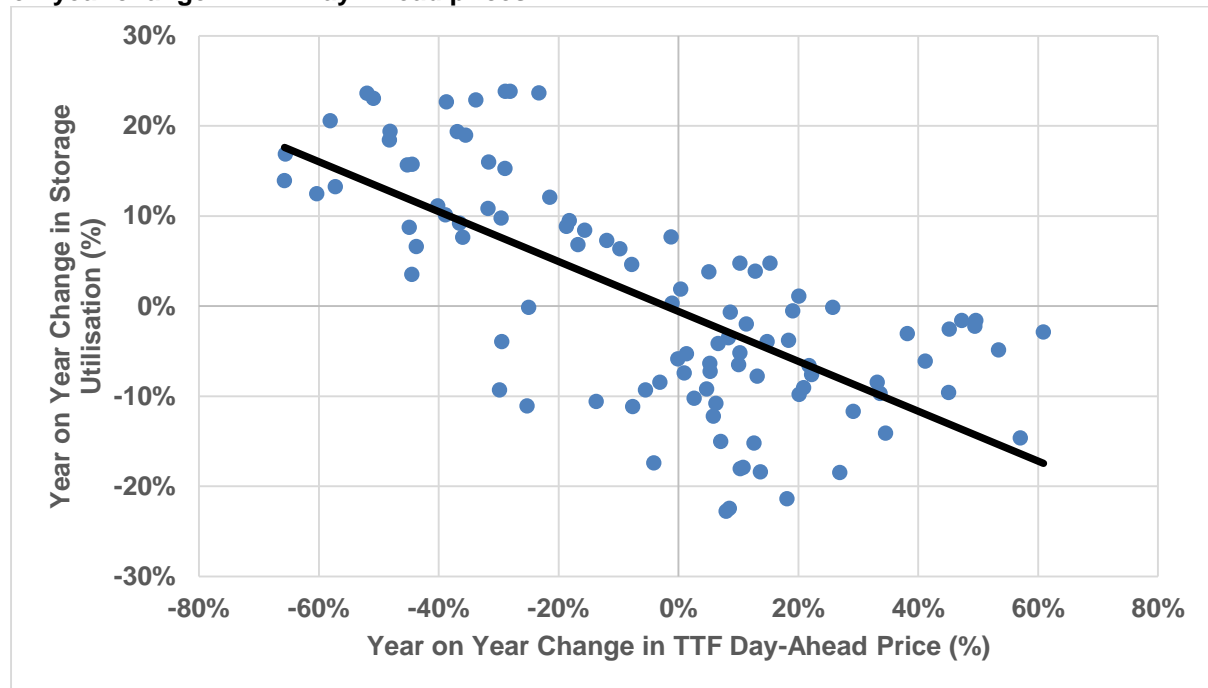
In Figure 7 we compare year-on-year percentage changes in storage and prices, rather than absolute levels. For example, throughout 2019, TTF prices were lower and storage utilisation higher year-on-year, reflecting a significant oversupply. The fact that storage utilisation has been higher, and prices lower, year-on-year in 2020 is because this oversupply has continued and even intensified, especially after the impact of COVID-19. In order to provide the right incentives for storage to be booked and utilised, the summer-winter spreads need to be wide enough to cover the full storage costs. If the forward prices for winter are looking weak, then summer prices will need to fall sharply, which is exactly what happened in 2019 and is happening again in 2020, with storage filling rapidly.

Figure 7: The relationship between year-on-year change in total EU storage stocks and the year-on-year change in TTF Day-Ahead prices



Source: Data from Argus Media (TTF prices) and Gas Infrastructure Europe (storage)

Figure 8: The relationship between year-on-year change in total EU storage stocks and the year-on-year change in TTF Day-Ahead prices



Source: Data from Argus Media (TTF prices) and Gas Infrastructure Europe (storage)

The relationship identified between year-on-year changes in prices and storage utilisation rates suggests that prices may be approximately forecast from storage utilisation rates, which may be easier to predict going forward. This holds at least to the extent of projecting that prices may be higher or lower than in the same period in the preceding year, rather than a forecast of absolute price levels.

Storage utilisation levels move relatively slowly from month to month, absent an enormous shock to the system, such as a major supply interruption. Storage injection and withdrawal volumes are small relative to the size of the overall stocks. Daily injection capacity, in Europe, is equivalent to 1.0% of the storage capacity, while the daily withdrawal capacity is 1.8% of storage capacity. Even this injection and withdrawal capacity is not fully utilised. Since January 2011, the record daily average injection in June 2019 equated to 0.44% of storage capacity, while the record daily average withdrawal in January 2017 equated to 0.74% of storage capacity. These record rates of injection and withdrawal are the equivalent of having a standard 80 litre bath tub, and slowly filling it using a 350 ml soft drinks can once a day, or emptying it using something only slightly larger than a (568 ml) pint glass once a day.

As a result, if storage stocks are particularly high now, we can be sure that they will remain so for the next several months, because the daily withdrawal rates are not high enough to dramatically alter the stock levels over a very short period of time.

The fact that storage stocks change at a relatively glacial pace compared to the rapid fluctuations in hub prices makes storage utilisation rates a valuable leading indicator for hub gas prices in the near-term future, given the correlation between the two illustrated in Figures 7 and 8. Indeed, three practical examples from the last year alone illustrate this phenomenon:

Firstly, storage stocks in October 2019 were substantially higher than twelve months earlier, as the market braced itself for a potential disruption of gas transit via Ukraine. Only such a disruption and/or a very cold winter could have brought storage utilisation rates back down to levels seen a year earlier. This made it likely that storage utilisation rates would remain higher year-on-year through to the end of Q1 2020, and that prices would likewise remain lower than a year earlier.

Secondly, as Europe reached the end of the winter storage withdrawal season in mid-March 2020 storage utilisation rates were substantially higher than a year earlier, and prices substantially lower. The oversupply on the European market at that time made it clear not only that further storage withdrawals would not take place to bring the storage utilisation rates down, but that net storage injections were likely to be higher than a year earlier in order to absorb excess volumes on the European market. This made it highly likely that European storage utilisation rates would be substantially higher in Q2 2020 than a year earlier, and prices accordingly lower.

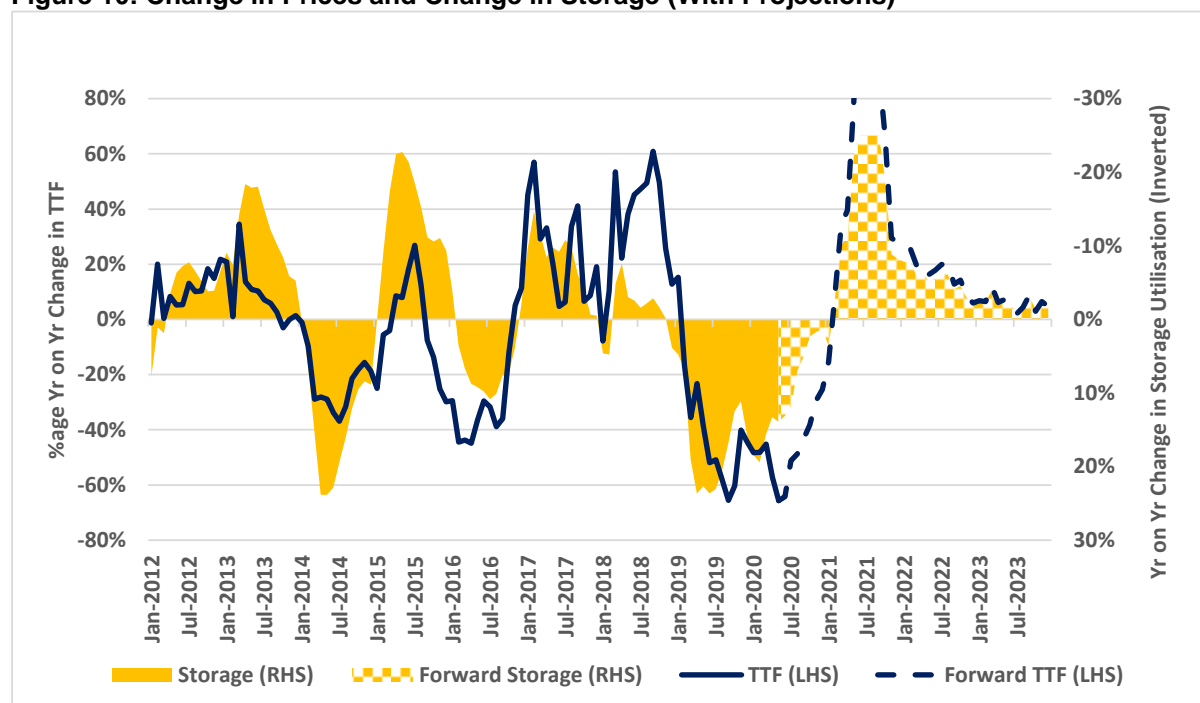
Finally, at the time of writing (June 15 2020), it is clear that the oversupply on the European market in Q2 and Q3 2020 is being intensified by the impact of the COVID-19 pandemic on gas demand. In this context, storage injections in April-May have brought European storage utilisation rates to record levels for this time of year. Furthermore, the ongoing global LNG oversupply, is motivating continued injections, meaning that European storage facilities will likely reach full capacity well before the end of summer, although the ability to utilise Ukrainian storage could alleviate the situation, to a modest extent, as discussed in the recent Comment on European gas storage.¹⁷

Where might prices go?

The forward curve for TTF in figure 5 suggested that prices in the second half of 2020 would be more than 40% below those in 2019. Based on the analysis underlying figure 7, this would lead us to the conclusion that the amount of gas in storage in Europe, for the rest of 2020, will be significantly higher than in 2019. With storage already being utilised at a much higher level than last year, this is certainly not that surprising. However, by 1 October 2019 storage was effectively full, so the situation in 2020 is expected to be broadly the same. The interesting bit is Q1 2021. The forward curve has TTF prices in Q1 2021 actually higher than in Q1 2020, a situation which persists through the year – the Q3 2021 forward curve for TTF is \$4.50 which is almost \$1 higher than the Q3 2019 actual price! Figure 10 shows the forward curve for TTF and, if the relationship between prices and storage utilisation, identified in figure 7 holds, then *implied* storage utilisation would decline significantly during the 2020/21 winter period. At the end of March 2020, gas in storage in Europe stood at 56 bcm – a utilisation rate of some 54%. From the beginning of October 2019 to the end of March 2020 45 bcm was withdrawn from storage. The higher prices of the forward curve in Q1 2021 would suggest that more gas would need to be withdrawn from storage during the 2020/21 winter, even if only by a small amount.

¹⁷ Pirani, S and Sharples, J., 2020. European gas storage: backhaul helps open the Ukrainian safety valve. *Oxford Energy Comment*. May 2020.

Figure 10: Change in Prices and Change in Storage (With Projections)



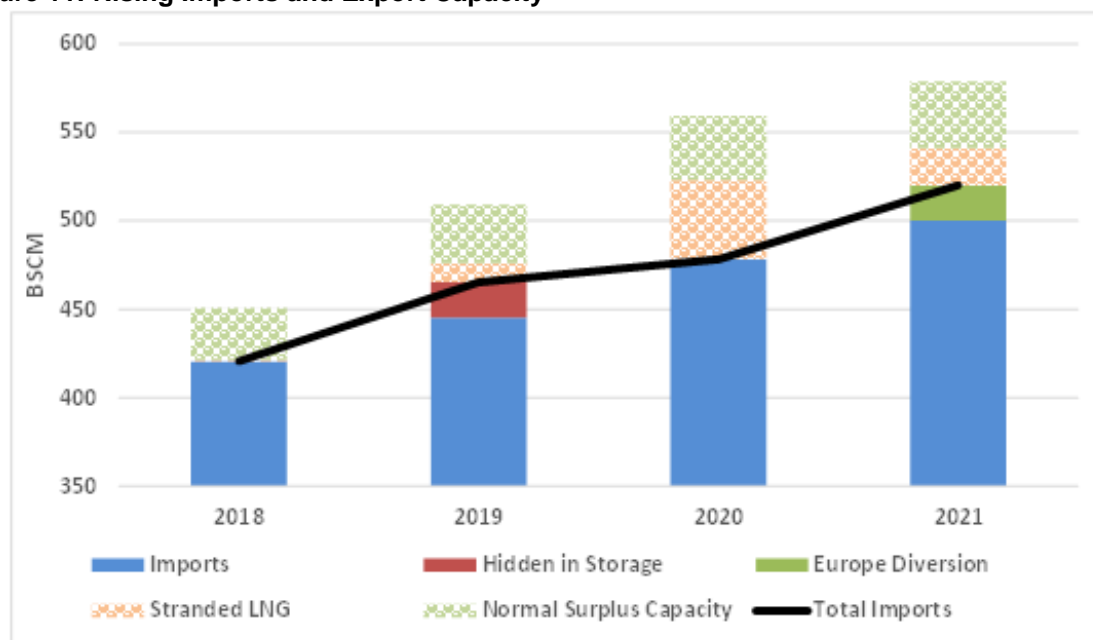
Source: Data from Argus Media (TTF prices) and Gas Infrastructure Europe (storage), OIES Analysis

Furthermore, the much higher forward prices in summer 2021 – double the summer 2020 prices (actual so far and forward) – would suggest much lower injection into storage as well. By the end of September 2021, rather than being full, it might be expected that gas in storage would be 20 to 30 bcm less than the anticipated largely full situation in September 2020, if the forward curve prices are to be realised, consistent with implied storage utilisation.

Even if European demand were to return to pre-COVID-19 levels in 2021, and pipeline imports, especially, remained at reduced levels, this would require a significant decline in LNG imports, of a similar amount to the reduced storage injections. If imports from Russia bounced back, then an even larger decline in LNG imports would be required.

For there to be a significant decline in LNG imports into Europe in 2021, especially in the summer months, it would require rising LNG imports in the rest of the world, especially in the Asian markets, and a slowdown in the growth of LNG supply. One positive factor is that the rapid growth in LNG export capacity we have seen over the last five years is pretty much coming to an end. Export capacity is only projected to rise by some 3% in 2021 over 2020, largely being the ramp-up to full capacity of the US LNG terminals coming on this year, Yamal LNG train 4 and the second Malaysian FLNG (PFLNG Dua) also ramping up, with the possible return of Damietta in Egypt. That only means, however, that the market doesn't need to absorb much more new supply coming on, although the substantial amount of LNG capacity not being utilised in 2020, might be looking to produce in 2021.

Figure 11: Rising Imports and Export Capacity¹⁸



Source: OIES estimates, IEA data, Platts LNG Service and Nexant World Gas Model

Figure 11 looks at the history and prospects for LNG imports and export capacity. From year to year, the key points are as follows:

- In 2018, available LNG export capacity¹⁹ was some 450 bcm, with some 420 bcm of total imports, leading to a utilisation rate of 93.3%. This level of utilisation was historically high and the unused capacity, of around 6.5%, could be regarded as “normal surplus capacity”.
- In 2019, export capacity rose by almost 60 bcm and total imports by some 45 bcm. Maintaining the 6.5% level of “normal surplus capacity”, would suggest some 2% of export capacity was “stranded LNG” – around 11 bcm since the volume of normal surplus capacity had risen. However, some 20 bcm of the rise in imports was hidden in European storage and not actually consumed in the market. This would add another 4% to the effective excess supply, which is why there was a sharp drop in global gas prices in 2019. The continued rise in export capacity in 2020 – another 50 bcm – together with the impact of COVID-19 on global gas demand, is dramatically increasing the volume of stranded LNG. Even with total LNG imports increasing year on year, stranded LNG could still increase to around 45 bcm in 2020 as a whole, or some 8% of total export capacity.
- In 2021, capacity growth is expected to slow, but demand is projected to increase, notwithstanding the fact that the lingering impact of COVID-19 may affect demand next year as well. In the Americas and MENA, very little rise in demand is expected. If Europe was assumed to import the same in total in 2021 as is expected in 2020, (which is also the same as the 2019 import level), then the amount of stranded LNG could decline to some 20 bcm or 3.5% of total export capacity. This could be achieved if total Asia demand rose by some 40 bcm, with China and India growing significantly, plus a sharp rebound in Japan, Korea and Taiwan - a rise of some 12%. However, Europe could not really absorb the same amount of LNG in 2021 as that would likely fill up storage again, and be inconsistent with the forward curve rebound in prices. To support the forward curve, some 20 bcm of LNG might have to be diverted from Europe to Asia (Europe Diversion in Figure 11). On that basis, Asia demand would need to rise by 60 bcm in total – or some 18%.

¹⁸ The scale has been truncated to aid the analysis

¹⁹ Available LNG export capacity is nameplate capacity less maintenance and any technical outages and any problems with feedgas plus the ability of some plants to produce more than nameplate.

If the outcome for Asian demand is not so strong, however, leading to a continued requirement for the absorption of LNG by Europe, this would suggest continuing low prices through 2021. The implication of that would be more shutting in of LNG, until such time as this helped prices recover a little. The incentive to shut in, if Europe (and Asia prices) were lower than the forward curve, would, in part, depend on the Henry Hub price as well. The forward curve, in Table 1, has the Henry Hub price rising to the \$2.50 range – pretty much back to 2019 levels. This seems largely to be based on much weaker associated gas production from the shale and tight oil plays, leading, in 2020 at least, to production declining more than total gas demand (both domestic demand and LNG exports). This might then feed through into 2021 and beyond. However, prices at these levels may be more than high enough to stimulate drilling in the drier Marcellus and Hayneville plays, dampening down the price increases. In such a case, if TTF and Asian prices were somewhat lower than the forward curves suggest, this might not necessarily lead to shut ins of US LNG, with Henry Hub also lower.

Table 1 - Forward Spot Prices

	Actual	Estimate	Forward		
	2019	2020	2021	2022	2023
Henry Hub	2.63	1.96	2.66	2.47	2.40
TTF	5.06	2.75	3.99	4.66	4.94
Japan	5.71	3.30	4.52	5.19	5.40

Source: OIES, based on data from Argus Media (Forward curve as of June 12th)

The forward curves for 2022 and 2023 suggest further increases in TTF prices as well as in Asia, with the latter also being influenced indirectly through oil-indexed long-term contract prices. Again, the logic of this is that European storage utilisation is lower than in 2020, notwithstanding the possibility of lower Henry Hub prices. Ultimately, for the market to rebalance without any significant shutting in of LNG requires a significant increase in demand for LNG in Asia, and limited extra supply entering the market. In turn this may require a rapid bounce back, and more, from the impact of COVID-19.

Could we see negative prices in Europe?

There has been some discussion as to whether we could see negative prices in Europe this summer, following on from the negative WTI price at the end of April. It should be said that the negative WTI price was largely a technical issue, as the close of the May contract required traders who were physically long in the market to try and offload volumes with no storage available. Oil prices since then have rebounded strongly.²⁰ A better example might be the negative Waha²¹ hub prices in 2019, where the increasing production of shale oil, with associated gas production, meant that the volume of gas could not be accommodated in the pipeline systems in West Texas to evacuate the gas to the key hubs and markets, in particular on the Gulf Coast. Again, this was an infrastructure issue in a localised area.

By contrast, the European gas market is very well interconnected, especially in Northwest Europe, and even if storage is completely full, pipeline gas suppliers, and also those buyers nominating under contracts, could turn volumes down in extreme circumstances. In addition, LNG could effectively be stored in tankers offshore, for a period, if there was no room left in the storage tanks at the regas terminals. The possibility of a sustained negative price in Europe, therefore seems unlikely, although on a particular day there remains the possibility of a technical negative price if a large source of demand, such as one or more power plants, has to shut down. This would be especially the case once European storage is close to being full, when the “moment of truth”, as our colleague Professor Jonathan Stern has said, arrives for the suppliers and buyers in the European market.

²⁰ Fattouh, B. and Imsirovic, A., 2020. Oil Benchmarks Under Stress, *Oxford Energy Comment*, April 2020.

²¹ US Permian basin hub

Conclusions

The impact of COVID-19 on the global and European markets has been felt since March 2020. In Europe, in the first five months of 2020 we have seen lower demand, lower pipeline imports, a modest decline in production, and a relatively modest drawdown of storage from high stock levels at the beginning of the year, but LNG imports have been higher than the already high 2019 levels.

At the end of May, storage utilisation in Europe was some 73%, leaving around 28 bcm of capacity available, which, based on last year's injection rate, is likely to be full sometime in August. LNG imports around the world have started to decline, but the big fall is slated for Q3 when there is simply no more room left in Europe to absorb the volumes. The forward prices for TTF through to the end of Q3 are under \$2/MMBtu, with Asian forward prices just above \$2, leaving the margin (on a variable cost basis) for US LNG in negative territory, by some \$1/MMBtu, on average, through October. As a result, US LNG cargoes scheduled for lifting in June and July, are being cancelled. Some 100 cargoes are reported to have been cancelled from the US. However, with LNG imports expected to drop sharply in Q3, another 130 cargoes, which would have been lifted in June and July, may need to be cancelled, to have any chance of balancing the market, even at a price in the low \$1/MMBtu in Europe. Once European storage is close to being full in late July or early August, the "moment of truth" will have arrived in the European and global markets. If there is still too much LNG trying to find a home, then unless pipeline suppliers to Europe pull back to an even greater extent than they have so far, it is possible that negative prices could be seen, for at least a short period of time, in Q3. We believe this scenario is not the most likely, although there could be a "technical" negative price on a few days if there are unexpected losses of demand, if for example gas-fired power plants went off line for short periods.

The level of utilisation of European storage facilities might provide some clues as to where prices might be going in 2021 and beyond. There appears to be a reasonably strong correlation between the year on year changes in TTF prices and the year on year change in storage utilisation. The current forward curve for TTF suggests more than a doubling of prices in summer 2021 compared to summer 2020, with further increases in 2022 and 2023. If the historic correlation between changes in TTF and changes in storage utilisation is to hold, this implies that there will be significant storage withdrawals this winter and restricted storage injections next summer. If this were to happen, then the room for LNG imports into Europe will be significantly curtailed. While the growth in LNG export capacity is slowing, if the current shut-ins we are seeing, and expect to see, in the next few months, are not to be repeated next year, then Asian LNG demand needs to rise sharply, possibly by as much as 60 bcm for the whole of 2021 over 2020 (some 18%). In the absence of this the current forward curve levels look too bullish.

As a result, prices in Europe, and in Asia, may stay at stubbornly low levels through 2021, prompting more shut ins next year, especially if Henry Hub rises as the forward curve suggests. However, at prices much above \$2, drilling in the dry gas Haynesville and Marcellus plays could be stimulated, holding back the rise in Henry Hub prices. The 2022 and 2023 TTF forward curves suggest further price increases, but again, it requires significantly rising demand for LNG, for these to be realised in the future. The further we go out the more likely this is, especially if Asian markets respond to the lower spot prices, although they have shown little sign, so far, of doing so. As a result, it is going to be very difficult to anticipate a return to the status quo, until there is greater evidence of a very strong demand recovery in key Asian markets.