THE OXFORD INSTITUTE FOR ENERGY STUDIES

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Quarterly Gas Review:
Short and Medium Term Outlook for Gas Markets

Introduction

In this latest OIES Gas Quarterly our objective is to continue our review of the impact of COVID 19 on global gas markets by examining various key indicators and also by updating our global gas model and extending the range of our forecasts to 2025. We start, as usual, with a look at various price indicators which demonstrate what we believe are some key market trends. Our LNG Tightness Indicator, which shows the margin for US LNG exporters, has improved slightly since last quarter but the cash margin remains negative through 2020. We have introduced a new chart which compares changes in storage utilisation and changes in the TTF gas price, which suggests that the forward curve is anticipating either a very significant surge in Asian gas demand in 2021 or another round of LNG shut-ins to support the gas price. Meanwhile, activity on Gazprom's ESP underlines the continued competitiveness of Russian gas in Europe and the increasing importance of the ESP as part of Gazprom's export strategy. In Asia the gap between oil-linked LNG prices and the JKM spot price is starting to close, but nevertheless remains wide enough to provide an incentive for customers to demand changes in pricing formulae. Finally, the domestic wholesale price in China has been falling, but also remains significantly above the level of the JKM price, underlining a key motivation for further price reform.

In addition to the price analysis we have four key-note articles this quarter. The first updates our analysis of the storage situation in Europe and the impact of LNG flows. It notes that storage injections have slowed recently and LNG imports in June have also declined sharply, and concludes that these outcomes relate to some extent to more robust gas demand in Europe than had been expected but has mainly been caused by LNG shut-ins that have reduced supply. Despite this, European storage utilisation remains at record levels for the time of year, and although the crunch point at which storage might actually become full has been pushed back by a few weeks, August and September remain critical months.

While LNG shut-ins are already playing a role in balancing the global market, the impact of Russian flows is also crucial, and our second article reviews physical flows via various transit routes in the first half of 2020. It notes the overall decline in Russian exports which occurred in January and then discusses the changing balance of export routes following the new transit agreement with Ukraine and the ending of the long-term arrangement with Poland. The article also notes the growing importance of volumes sold on the ESP, which have accounted for 17.5 per cent of total sales in 2020 to date.

The third article updates our forecasts for global gas supply and demand, with a focus on the LNG market, in the wake of the COVID 19 crisis and extends the analysis to 2025. Its overall conclusion is that global gas demand can rebound to 2019 levels in 2021, but that it will be 2025 before the full impact of the COVID 19 crisis has unwound as it will take five years before our previous pre-COVID base case forecasts can be met. In addition, our expectation is that although prices are set to recover gradually over the next few years as the global supply and demand balance tightens, they will struggle to exceed $6/mmbtu and may well go into decline again from 2025 as a new wave of LNG supply emerges.

Finally, we return to the theme of Russian gas exports and look at Gazprom's developing Asian plans, which were the focus of the company's recent AGM. The Power of Siberia pipeline is now up and running and will gradually work towards full capacity of 38bcma over the next 4-5 years, with the possibility of expansion to 44bcma if current negotiations are successful. In addition, plans for a second export route from West Siberia via Mongolia are also being discussed which could add a further 50bcma of capacity, while a third pipeline option would run from Sakhalin Island to the Chinese border near Vladivostok. Expectations for both these new routes must be tempered by the knowledge that negotiations over price, in particular, will take some time, but Gazprom CEO Alexei Miller has been keen to underline that Russia's plans to reduce its dependence on the European market are set to accelerate.

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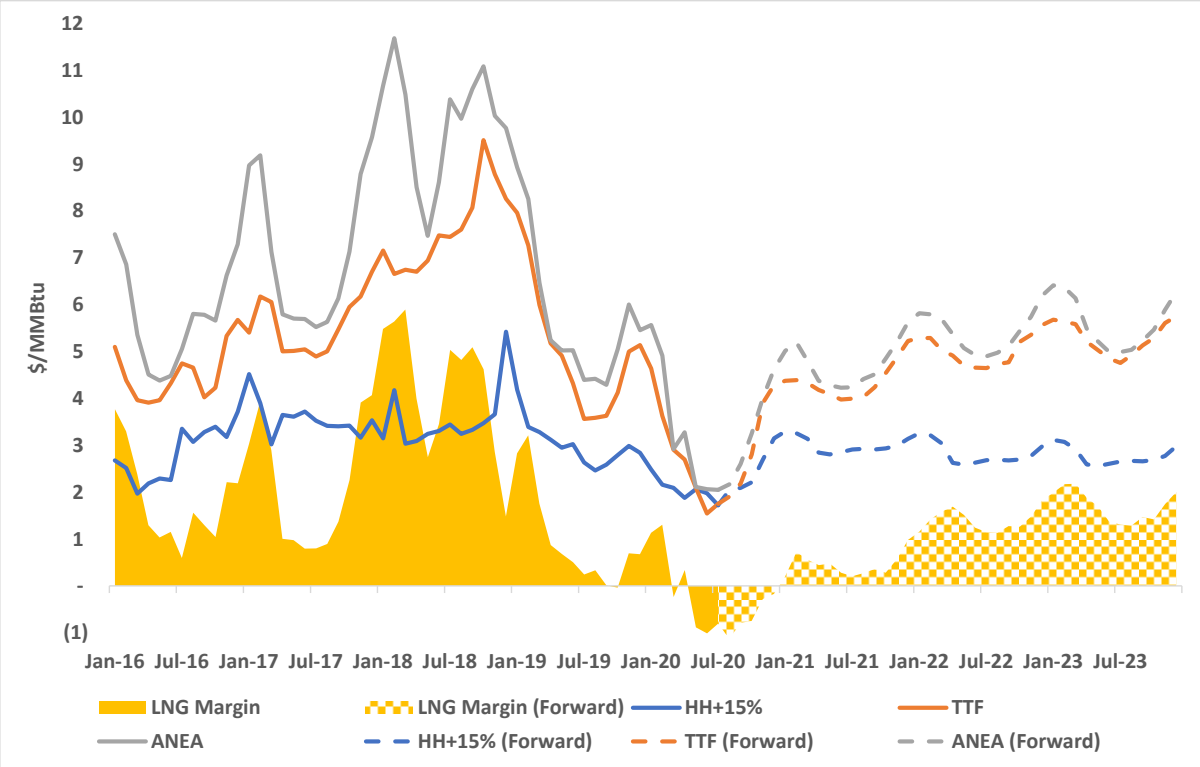
1. Price Analysis

Before taking a look at our topics for the quarterly, we include below our regular review of some key pricing trends for global LNG, Europe and Asia, as well as introducing a look at price volatility for the first time.

1.1 LNG Tightness – cash margins have gone negative

Firstly, we consider our "LNG Tightness" analysis as an indicator of how profitable existing export projects are and whether there is a need for new FIDs in an already oversupplied global market. The graph below is based on data from Argus Media and shows the prices for TTF in the Netherlands, the ANEA spot price in Asia and the Henry Hub price[1] 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 then shown on a historical basis and also based on futures prices, and provides an indication of whether developers in 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). A margin in excess of $3 – as it was in 2018 - would provide an obvious incentive for new projects while a margin well below this suggests a more oversupplied market.

Figure 1.1: An Assessment of "LNG Tightness"[2]



Source: OIES, based on data from Argus Media

It will be no surprise to readers that the margin is currently reflecting a heavily oversupplied market, and indeed is negative for the remaining months of 2020. This means that an average US LNG cargo would not cover its short-run marginal cash costs delivering to Europe or Asia at current prices. As a result, a number of customers with contracts to purchase US LNG have taken the option to turn down delivery, leading to the effective shut-in of capacity. This reaction has started to have an impact on the futures curve for TTF and ANEA as traders anticipate that supply side curtailment may start to tighten the market in 2021. The LNG tightness margin turns slightly positive in 2021 (an improvement on our most

[1] 115 per cent of Henry Hub
[2] Forward curve as at July 10 2020

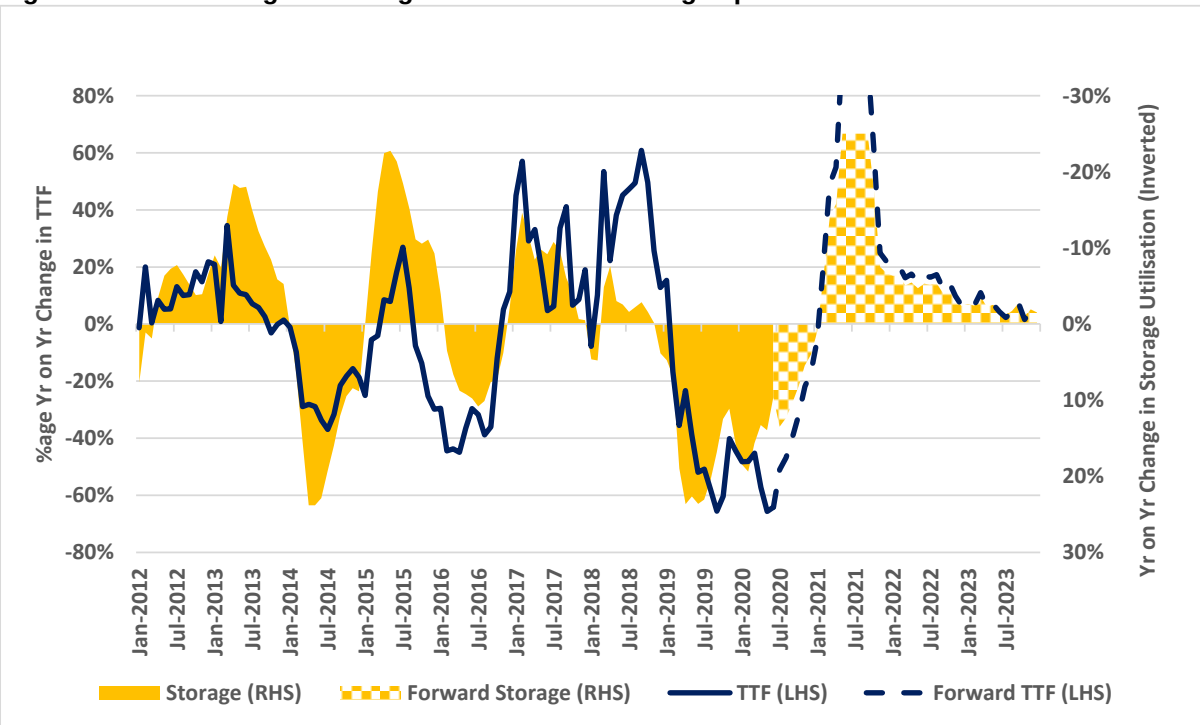
recent analysis when it was negative through the first half of 2021), but it remains to be seen whether this will in turn just encourage a much smaller turndown in supply and bring prices back down again. Over the longer term the margin does improve, but it does not reach the $3/mmbtu level that would encourage new investment before the end of 2023. It is therefore clearly relevant to ask whether we should expect to see any new US LNG investment decisions being taken in the foreseeable future, especially with buyers not rushing to sign new long-term contracts.

1.2 Movements in European storage utilisation and gas prices

As another measure of the state of the gas market we have developed a methodology to compare the futures curve for TTF and the implications for storage levels in Europe. Figure 1.2 shows the historical correlation between the year-on-year change in storage utilisation and the year-on-year change in the TTF gas price in Europe. As we identified in a recent paper[3] there appears to be a relatively strong correlation between the two measures, and while any statistician knows that correlation does not imply causality it would seem that the two are both driven by the same supply and demand factors. As a result, if one can estimate the outcome for one of the measures, then one can make a reasonable prediction for the other.

The outlook for storage utilisation is generally easier to predict than that for prices, since changes in the former tend to move relatively slowly. However, we can reverse this as the futures curve provides a market-based outlook for prices from which one can infer an implied outcome for storage utilisation. One can then assess what the implications of this implied outcome are and therefore whether they are credible. By a process of reverse logic one can then provide an opinion on the underlying market conditions that must underpin the forward curve.

Figure 1.2: YoY change in storage utilisation and TTF gas price



Source: OIES, with data from Argus Media

The graph above plots the YoY change of the forward curve through to 2023 and also plots the implied change in storage utilisation (inverted) that should implicitly accompany this price movement based on the historical relationship. With the forward curve currently showing a sharp increase in the TTF price

[3] Fulwood M. & Sharples J. (2020) "$2 gas in Europe (Part III): Down, down, deeper and down", Oxford Energy Comment, Oxford Institute for Energy Studies

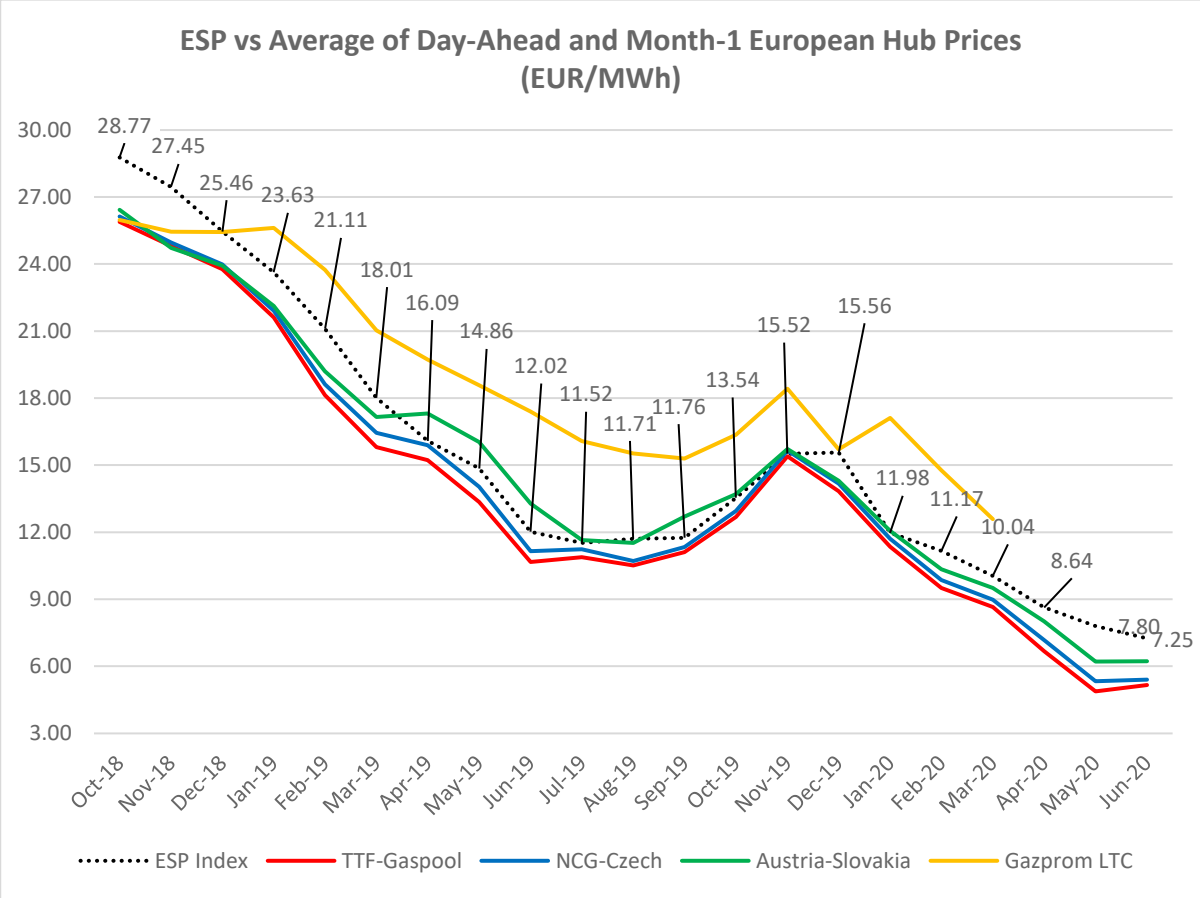
to just over $4/mmbtu in Q2/Q3 2021, compared to $2/mmbtu this year, the implication for storage levels in Europe is that they must be set to fall very significantly compared to 2020. Our calculations suggest that storage utilisation would need to fall by around 25 percentage points in summer 2021 compared with this year to justify such a sharp rise in the gas price, implying a utilisation rate of around 66 per cent, or 68bcm of gas in storage. While this is not without precedent, as similar levels were seen in 2017 and 2018, market conditions in 2021 are likely to be very different. European demand is expected to recover, somewhat, from its collapse in 2020, and overall global demand may reach the levels seen in 2019, but supply will also have continued to rise sharply as existing projects continue to ramp up and new projects come online. As a result, it would seem that only two occurrences could result in storage levels falling to this level next year. Either a significant amount of LNG supply would need to be shut in (we would tentatively suggest around 20 to 30 bcm) or else Asian demand, which has been very resilient in 2020, will need to grow much more rapidly than most forecasters expect. If neither of these outcomes transpire, and especially if European storage fills again in 2021, as it did in 2019 and is doing again this year, then it would seem that the futures price for TTF could prove somewhat optimistic. We leave it for readers to draw their own conclusions.

1.3 The Price at Gazprom's Electronic Sales Platform

One other source of flexibility in Europe is pipeline supply, and a key component of that is Russian gas exports. We therefore believe it is important to monitor key indicators of Gazprom's sales strategy in Europe, one of which can be found by examining the activity on the company's Electronic Sales Platform. The ESP, as it is known, is used to sell extra Russian gas to fill pipeline export capacity and to top-up long-term contract sales. Indeed, for some time now the ESP Index (the average of ESP prices across a number of delivery points) has shown a price lower than Gazprom's LTC price, and this has continued in 2020. However, while January and February showed a dramatic increase in volumes of short-term gas on the Platform, indicating that Gazprom was offering very competitive gas to make up for a decline in long-term contract sales (as buyers had been nominating down to take-or-pay levels due to lower demand and the availability of cheap gas on European hubs) the rest of H1 has shown a marked change in strategy. Although the ESP price has remained very competitive, as shown in the graph below, the majority of sales are now for month, quarter, season or even year ahead, indicating that Gazprom has no intention of actively engaging in a short-term price war but is now trying to lock in longer-term sales in a very difficult market. As a result, although Russian gas remains very price competitive and is certainly a threat to LNG arriving in Europe, it would at least seem that Gazprom is not keen to see the short-term price in Europe go any lower.

As far as the medium term is concerned, though, Gazprom has been expanding sales in an attempt to secure market share and bolster overall sales as its long-term contracts have come under pressure (see later article). In June 2020, for example, there were no sales for prompt delivery at all, with sales for Q3 accounting for 41 per cent of total trades on the ESP and with sales for calendar year 2021 accounting for the next largest share at 29 per cent. The conclusion to be reached is that Gazprom is using the ESP to remain price competitive and also to generate sales over a range of time periods in order to provide an important alternative source of revenue.

Figure 1.3: The Price at Gazprom's Electronic Sales Platform versus European Hubs



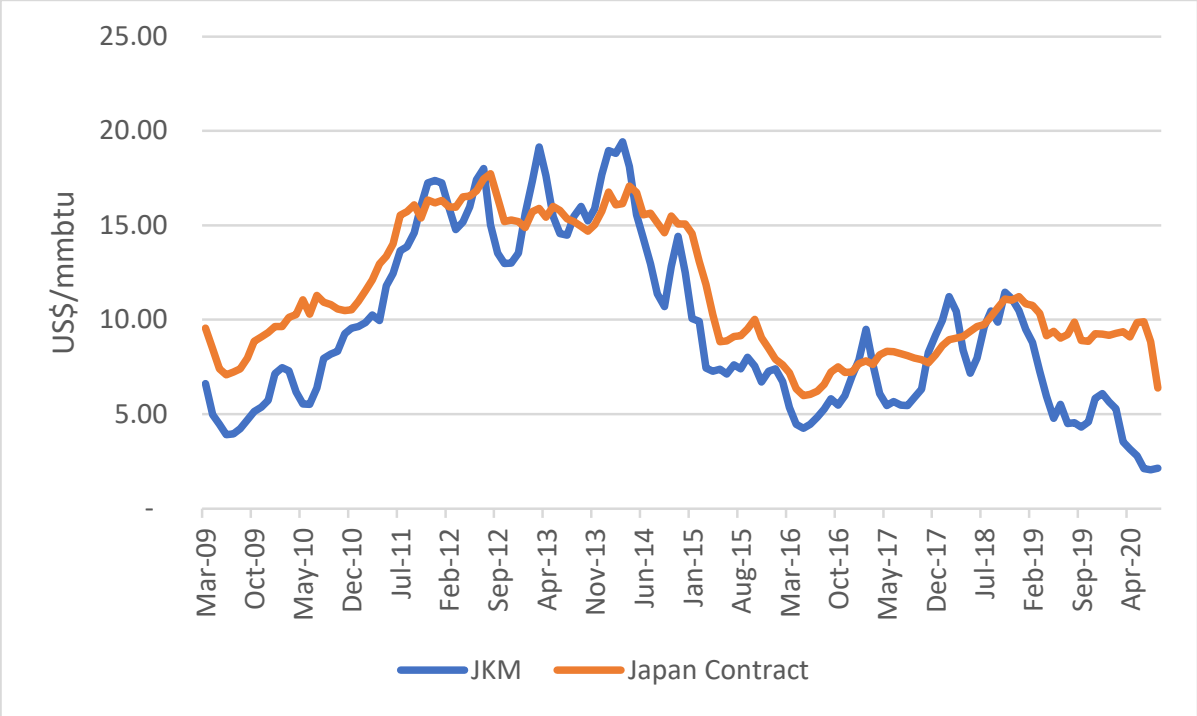
Source: GazpromExport, Argus Media, OIES

1.4 JKM spot price versus LNG contract price in Asia

The relationship between contract and spot prices in Asia continues to be of significant interest. As we have noted at various times, customers tend to demand change in the formation of prices when their impact causes them to suffer very substantial financial losses. This certainly occurred in Europe when spot and contract prices diverged and customers began to demand a move from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation. The trend away from oil-linked pricing in Asia has been much more gradual, and indeed some might argue that it has barely started, but as Figure 1.4 shows, a significant divergence between spot and contract prices emerged in 2019 and then widened in the first five months of 2020, creating a significant incentive for customers to act at a time when buyers clearly have significant bargaining power. The instance of arbitration cases has started to increase, albeit from a low base, and rumblings of discontent from those tied into higher-priced oil-linked contracts has grown. Although Covid-19 issues remain more important at present, there seems little doubt that if this trend persists we could see a real challenge to oil-linked pricing of LNG in Asia, with the JKM marker already becoming an increasingly important price benchmark.

As we noted in the previous quarterly, low oil prices at the start of the year will feed through into contract prices in the second half of 2020, and evidence of this is already emerging in June, as can be seen from the graph below. However, the spot price remains more than $3.50/mmbtu below the contract price, and it remains to be seen whether the oil-linked price will reach parity with JKM given the likely rebound in the JCC price from its April/May lows. It will certainly be important to monitor this going forward, and it may be the case that the momentum for change in pricing methodology has already become unstoppable.

Figure 1.4: JKM spot price versus Japan LNG contract price (US$/mmbtu)



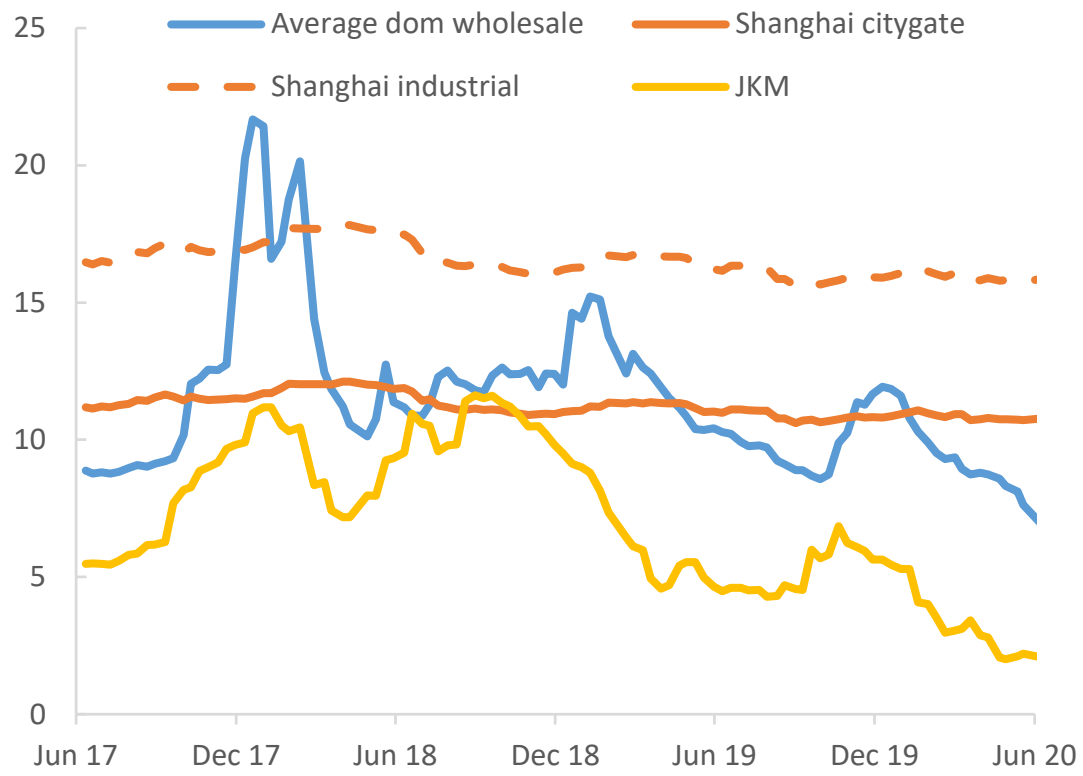
Source: Platts data, OIES analysis

1.5 Chinese domestic price versus LNG import price

An increasingly important indicator in Asia will be the Chinese domestic gas price versus the LNG import price level, and we are now monitoring this on a quarterly basis. The market continues to expect that low spot JKM prices will filter through to domestic prices, leading to an uptick in China's gas demand. But as the chart below highlights, domestic city gate prices (taking Shanghai as an example) remain well above JKM (and other international prices for that matter), although the average domestic wholesale price is at least trending in the same direction. This price, which is assessed by the National Bureau of Statistics every ten days, has been falling steadily over H1 2020 (in no small part thanks to changes in the RMB/US$ exchange rate) and is now more than $4/mmbtu lower than its 2018-19 average. However, it has not fallen as fast as JKM and at $6.78/mmbtu it still represents a hefty burden for industrial and commercial users. Going forward, the government has mandated cuts to city-gate prices, and with oil-linked contract prices also expected to decline in the second half of the year as the impact of lower oil prices kicks in, the differential to JKM should start to narrow.

As a result, the impetus for changing the domestic pricing mechanism is increasing. While the government is unlikely to liberalise prices altogether, it will want to see domestic prices reflect international movements more regularly. Yet while Beijing wants lower prices to encourage end-user demand, it would also like to maintain sufficient incentives for the majors to keep producing domestic gas, suggesting that some level of administrative intervention will remain. Nevertheless, reform efforts do seem to be continuing despite the overwhelming impact of the Covid-19 pandemic and we will continue to monitor this price trend through 2020.

Figure 1.5: Chinese gas prices compared to JKM (US$/mmbtu)



Source: Platts

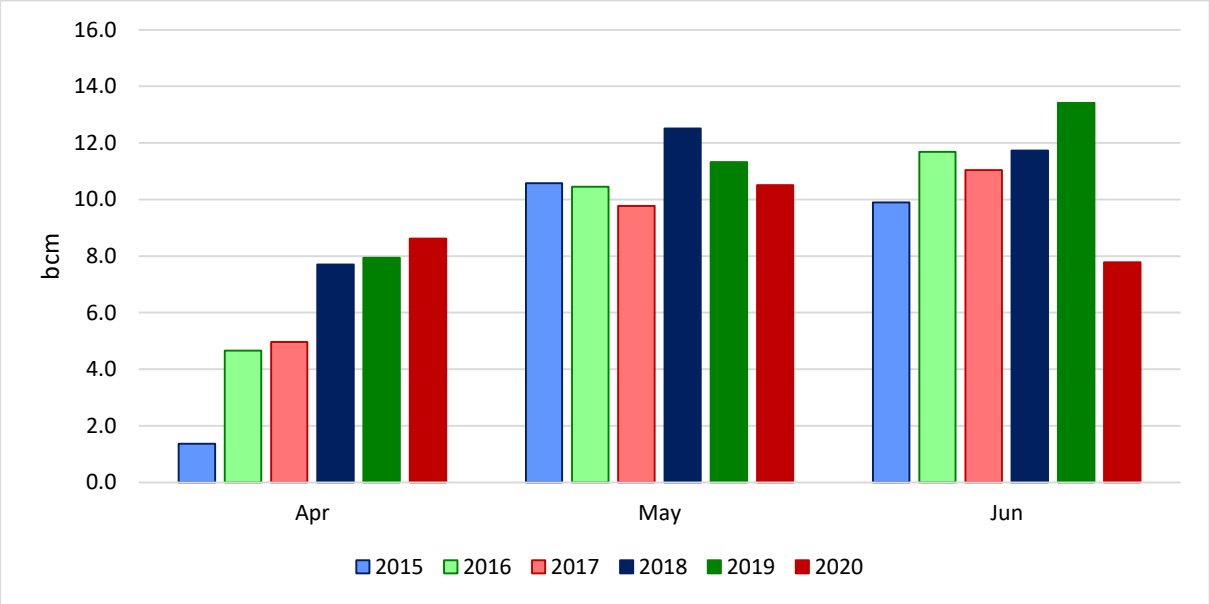
2. Slower than expected European storage injections in June push back potential 'crunch point'

In the May 2020 issue of the *Gas Quarterly*, we noted that Europe (EU plus UK) began the year with a record amount of gas in storage. Storage withdrawals that followed in Q1 (35.5 bcm) were higher than withdrawals in Q1 2019 (29.5 bcm), but slightly below the average for 2015-2020 (37.9 bcm). As a result, Europe ended Q1 2020 with record storage stocks for that time of year (56.0 bcm). That was significantly higher than both storage stocks at the end of Q1 2019 (41.6 bcm) and the average for the end of Q1 in the period 2015-2020 (33.8 bcm).

In the first part of Q2 2020, we noted the quicker-than average storage injections, and concluded that if storage injections in the remainder of Q2 continued at the same rate as 2019, European storage could be effectively full by early August. This, in turn, would limit the capacity of the European market to absorb LNG from the (currently supply-long) global market.

With data now available for the whole of Q2 (Figure 2.1 below), we can see that net storage injections in April 2020 (8.6 bcm) were indeed higher than April 2019 (7.9 bcm) and the average for 2015-2020 (5.9 bcm). Storage injections increased to 10.5 bcm in May, which placed them slightly below the 2015-2020 average (10.9 bcm) and injections in May 2019 (11.3 bcm). Finally, net storage injections in June (7.8 bcm) fell well below the 2015-2020 average (10.9 bcm) and showed a significant decline on net injections in June 2019 (13.4 bcm).

Figure 2.1 European net storage injections by month (bcm)



Data source: Gas Infrastructure Europe (GIE) Aggregated Gas Storage Inventory (AGSI)

As a result of the lower-than-average injections in June, the total net storage injections in Q2 2020 (27 bcm) were 16-18 per cent lower than in 2018 and 2019 (32-33 bcm), and back closer to the levels of 2016 and 2017 (26-27 bcm). As a result, the gap between the absolute volume held in storage in June 2020 compared with June 2019 began to narrow (see Figure 2.2, below). Despite this, by July 1 2020, the amount held in storage (83.3 bcm) was still 12 per cent higher than the amount held in storage on the same date in 2019 (74.7 bcm).

The relative slowdown in storage injections may be attributed to the fact that some storage facilities themselves are heading toward full capacity. For gas storage across Europe as a whole, stocks were at 80.5 per cent of capacity at the end of Q2. This level was reached three weeks later in 2019, and not until mid-September in both 2017 and 2018.

There are some interesting differences across the continent, however. In central Europe, the situation is more pressing. Austria, the Czech Republic, Germany, Hungary, and Slovakia account for 42.5 per cent of European storage capacity, and their stocks equalled 86 per cent of capacity on July 1, up from 81 per cent on June 1. At the June injection rate, storage stocks will pass 90 per cent of capacity by early August and 95 per cent by early September. The storage capacity available on July 1 equated to around 6 bcm.

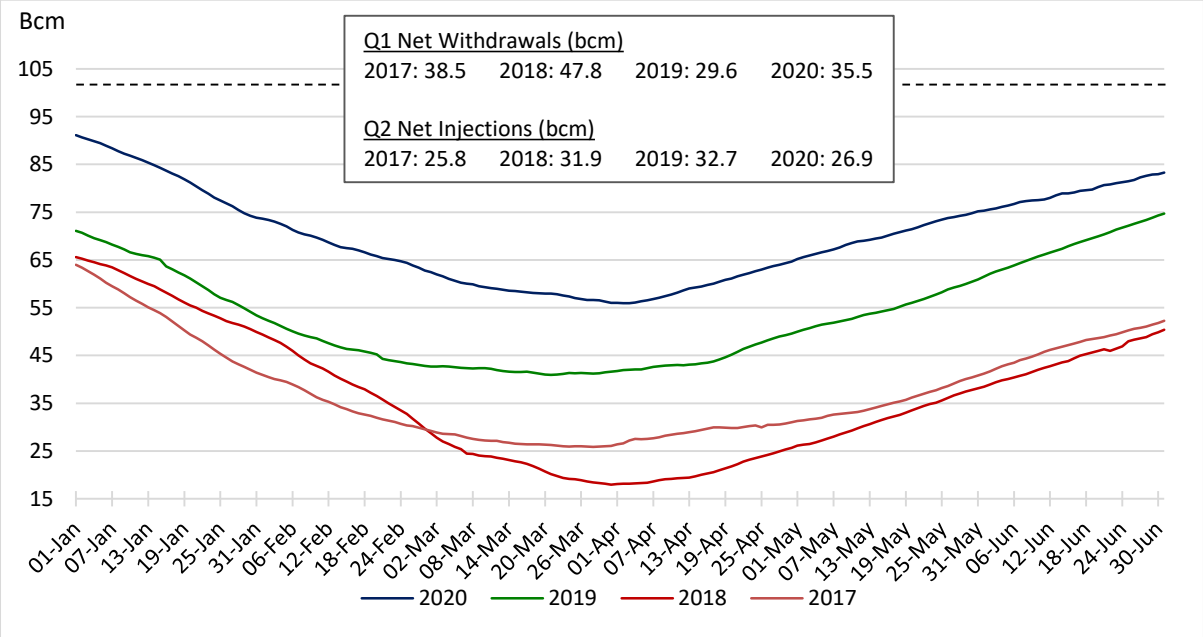
By contrast in the LNG-importing countries of north-west Europe (UK, France, Belgium, and the Netherlands), storage utilisation rates are slightly lower but absolute storage capacity is smaller. The storage capacities of these four countries combined accounts for 26.2 per cent of the European total. On July 1, their combined stocks equated to 77 per cent of combined storage capacity, up from 66 per cent on June 1. At the June injection rate, storage stocks will pass 90 per cent of capacity by mid-August, and 95 per cent by the end of that month. As in central Europe, available storage capacity in north-western Europe equated to 6 bcm on July 1.

In the main LNG-importing countries of southern Europe (Spain, Portugal, and Italy), combined storage stocks were 79 per cent of capacity on July 1, up from 70 per cent on June 1. The storage capacity available on July 1 equated to 4.5 bcm, with total storage capacity in these three countries combined accounting for 21.2 per cent of the European total. At the June injection rate, storage stocks will pass 90 per cent of capacity by mid-August and 95 per cent by early September.

Finally, given that total European storage stocks reached 95 per cent of capacity in mid-September 2019, if storage injections in Q3 2020 match those of Q3 2019, Europe will reach effective full capacity

three weeks earlier this year, that is, by late August. However, if the injections continue to be lower year-on-year, as in June, the 'crunch point' of full capacity will be pushed back into September. Crucially, this is closer to the start of the storage withdrawal season, thus lessening (but certainly not obviating) the potential effect of full storage limiting Europe's ability to absorb imports.

Figure 2.2 European Q2 net storage injections by year (bcm)



Data source: GIE AGSI. Note: Total European storage capacity (103 bcm) is indicated by the dotted line.

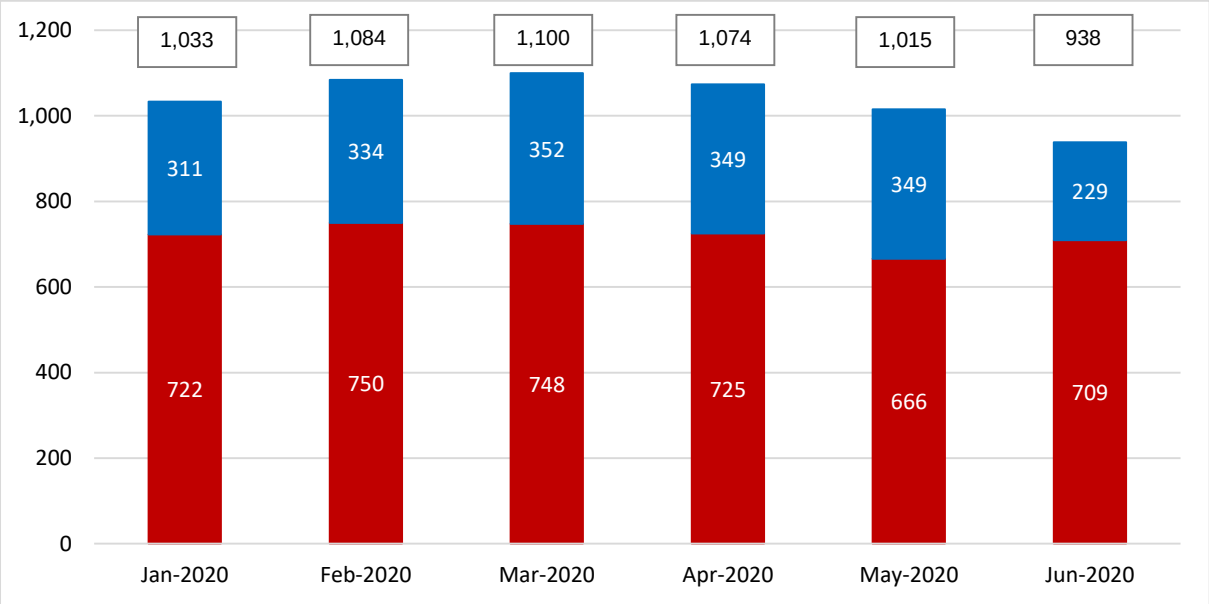
This slight change in the trajectory of storage utilisation is not just driven by the fact that storage tanks are approaching capacity, though. Another clear reason would seem to be that supply arriving into Europe has been falling consistently over the second quarter of 2020. The latest data suggests that total European imports (LNG and pipeline supplies combined) have fallen continuously since March (see Figure 2.3), as the COVID-related lockdowns impacted demand. During that period, LNG imports initially held steady at around 350 mmcm/d, while pipeline imports absorbed the impact, falling from 748 mmcm/d in March to 666 mmcm/d in May. However, in June, that trend was reversed: LNG imports fell by 34 per cent month-on-month, from 349 mmcm/d to 229 mmcm/d (-120 mmcm/d), while pipeline imports rose by 6.5 per cent, from 666 mmcm/d to 709 mmcm/d (+43 mmcm/d). This meant that between May and June, total imports (pipeline and LNG combined) fell by 7.6 per cent (-77 mmcm/d), from 1,015 mmcm/d to 938 mmcm/d.

A further reason may be that gas demand in Europe has held up rather better than expected in Q2. Naturally there has been a seasonal fall, and the initial impact of the economic shutdown caused by the COVID 19 lockdown in March and April was dramatic, but more recently the demand decline has slowed and indeed the sum of total supply (production plus imports, minus net storage injections) fell by just 5 per cent between May and June compared to a more "normal" seasonal decline of 15 per cent in the same period in 2019. This would seem to indicate that the gradual re-opening of some European economies is having an impact on gas demand, together with the competitiveness of gas v coal and lignite in the power sector.

However, the slowing of injection into storage in Europe would also seem to reflect an overall reduction in LNG supply. At a global level, LNG production fell by 8 per cent between May and June, from 1,290 mmcm/d to 1,187 mmcm/d (-103 mmcm/d). The fact that it did so serves to highlight the extent to which the global market is oversupplied, leading to widely reported shut-ins as off-takers react to low prices and diminished demand. Another possible explanation for lower LNG supply to Europe could be higher demand in Asia, which would drag LNG supply away from the Atlantic Basin. However, this did not materialise in the second quarter. Asian LNG demand has been remarkably robust in the face of the

pandemic, mainly thanks to the continued growth of the Chinese gas market, but overall demand in Asia was essentially flat in Q2, with some growth in the "Big 5" demand centres (Japan, Korea, Taiwan, China and India), offsetting declines in the emerging Asian markets. There was some evidence of Qatari and Nigerian volumes being re-directed to India and away from Europe in June, but overall there has been no dramatic demand pull from the East. It can therefore be concluded that the reduction of LNG deliveries to Europe is mainly a reflection of LNG supply being shut in, as reflected in cargoes from the US being cancelled, for April and May liftings, and therefore not being delivered in June.

Figure 2.3 European gas imports: Pipeline, LNG, and the combined total (monthly average mmcm/d)



Data source: Platts, ENTSOG Transparency Platform and National Grid (UK)

Looking forward, it would seem that the global LNG oversupply is set to persist for the foreseeable short-term future, with pipeline suppliers to Europe retaining substantial upside potential should European demand show signs of recovery. Despite the slowdown in European storage injections, Europe remains on course for storage stocks to reach full capacity earlier than in 2019, albeit several weeks later than we anticipated in our previous analysis. The 'moment of truth' will arrive when storage is no longer available to absorb excess imports, and winter seasonal demand has not yet made itself felt. If this coincides with a potential 'second wave' of COVID infections and related lockdowns in late summer, the effect will be markedly more dramatic. Meanwhile, although the absence of a second wave, combined with a relatively brisk economic rebound and the possibility of a cooler-than-average weather in September could lessen this impact, it is very likely that any signs of a tightening market and higher prices would catalyse an increase in the availability of LNG and pipeline gas in Europe, thus tempering the beneficial impact of even the most favourable scenario.

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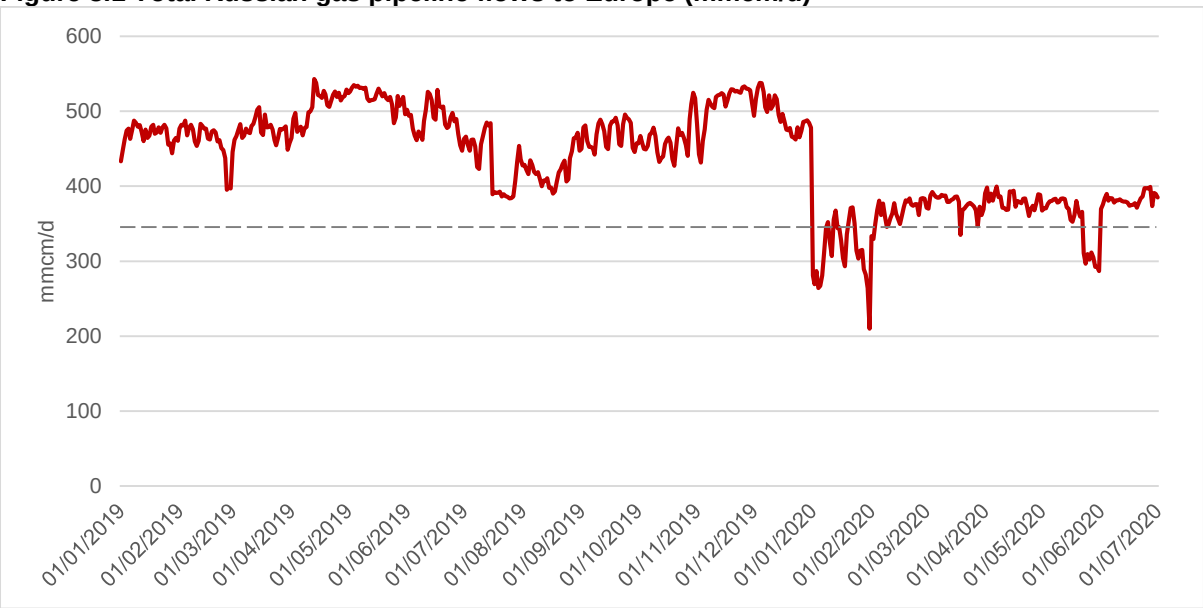
3. Russian Gas Export Flows

Given the size and flexibility of its production and exports, Russian gas flows to Europe are a crucial balancing factor in the European gas market, and by proxy the global LNG market. In the prices section above we have discussed the latest trends in prices on Gazprom's Electronic Sales Platform (ESP) which acts as a key indicator of Russian strategy with regard to export sales, and in this article we assess the flows of pipeline gas to Europe both in total and by various routes. We discuss the decline in exports in 2020 and the changing balance of transit routes following the conclusion of the transit agreement with Ukraine in December 2019 and the end of the long-term transit agreement with Poland in 2020. We also review the growing importance of the ESP as a vehicle to enhance Russian gas exports to Europe.

Total flows

Total Russian pipeline exports to Europe (EU plus UK, Switzerland and non-EU Balkans, minus Finland, Estonia, Latvia, and Lithuania) dropped sharply between December 2019 (15.3 bcm) and January 2020 (9.7 bcm), but have since recovered to a stable level of 10.6-11.7 bcm per month since February. Most recently in June, pipeline supplies to Europe grew by 5.2 per cent from 10.91 bcm in May to 11.47 bcm last month. This is the equivalent of a daily rate of 352 mmcm/d in May rising to 382 mmcm/d in June.

Figure 3.1 Total Russian gas pipeline flows to Europe (mmcm/d)



Data source: ENTSOG Transparency Platform. Note: Dotted line represents 350 mmcm/d.

The main entry points for Russian gas entering the European market are Greifswald (Nord Stream), Kondratki on the Belarus-Poland border (the Yamal-Europe pipeline), and Uzhgorod-Velké Kapušany on the Ukraine-Slovakia border. Until January 2020, substantial volumes for delivery to Romania, Bulgaria, Greece, and Turkey were also seen at Isaccea on the Ukraine-Romania border. However, the launch of TurkStream as a means of supplying the Turkish, Bulgarian, and Greek markets has reduced the role of Isaccea to supplying residual flows to the Romanian market. Flows from Bulgaria to Turkey at the Malkoclar interconnection point on their border have been displaced by gas flowing in the opposition direction at the Strandzha-2 interconnection point. The 'total flows' in the graph above discounts supplies to the Turkish market, by subtracting flows at Malkoclar from flows at Isaccea, but includes supplies to the European market via Turkey by including flows at Strandzha-2.

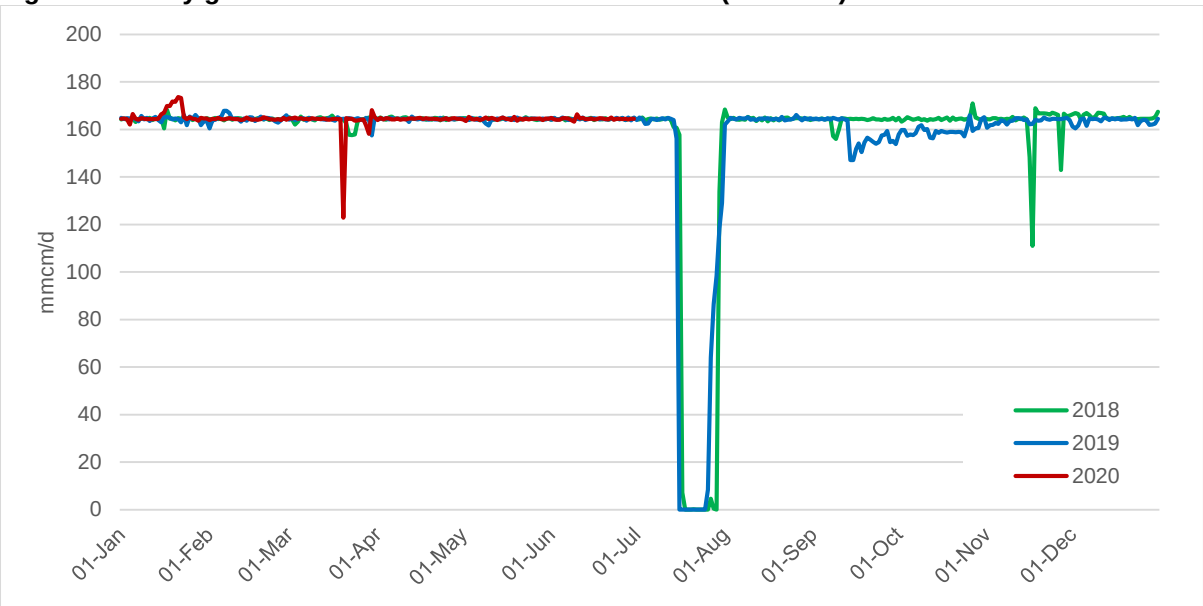
Focusing on recent developments, the graph above illustrates that since the beginning of February, total flows have largely been between 350 mmcm/d and 400 mmcm/d, with the exception of the last ten days of May, when they fell to around 300 mmcm/d. In June in particular, those flows were 370-400 mmcm/d. In this context, it is interesting to consider how Gazprom is managing those flows, given the

ongoing discussions around the potential completion of Nord Stream 2, the expiry of Gazprom's long-term transit contract with Poland, the impact of the Russia-Ukraine transit agreement of December 2019, and the ongoing development of pipelines in SE Europe that will, if all goes to plan, connect Hungary with TurkStream by October 2021.

NW Europe: Nord Stream and the Yamal-Europe pipeline

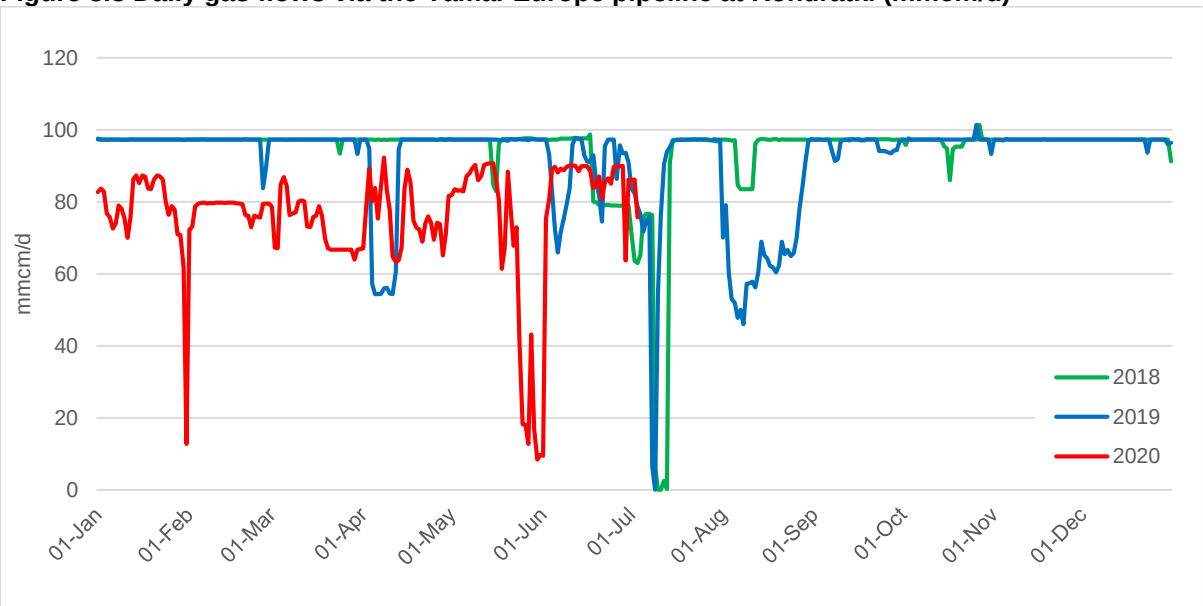
Given that the Nord Stream and Yamal-Europe pipelines terminate in NW Germany, and so effectively serve the same market (Gaspool), it is interesting to note the substantial difference in utilisation rates. As the two graphs below illustrate, Nord Stream has been fully utilised throughout H1 2020. By contrast, the Yamal-Europe pipeline has seen flows in H1 2020 generally around 20 mmcm (20 per cent) lower than in the same periods in 2018 and 2019, when it was generally used at its full capacity of 97 mmcm/d.

Figure 3.2 Daily gas flows via Nord Stream at Greifswald (mmcm/d)



Data source: ENTSOG Transparency Platform

Figure 3.3 Daily gas flows via the Yamal-Europe pipeline at Kondratki (mmcm/d)



Data source: ENTSOG Transparency Platform

The generally lower year-on-year utilisation of the Yamal-Europe pipeline reflects a lower European call on Russian gas throughout the whole of H1 2020, which has also impacted Gazprom's export flows via Ukraine. More recently, fluctuations in the utilisation of the Yamal-Europe pipeline have been linked to the Russia-Poland gas transit agreement, which expired on May 17. Indeed, it would seem that following the end of this contract, Gazprom has adopted a new strategy for use of the Yamal-Europe route.

On May 5 and 18, two capacity auctions were held, for the periods July 1 to October 1 and June 1 to July 1, respectively. In both cases, Gazprom booked 80 per cent of the capacity, indicating that it expected lower flows than in previous years. Furthermore, between May 17-31 Gazprom was able to book daily capacity under EU rules, and during this period it exercised its right to book (and pay) for only capacity that it needed. As a result, after several days of fluctuation, flows fell to very low levels between May 24-31. At the western end of the pipeline, exit flows on the Polish-German border fell to zero, while limited entry flows at Kondratki served the Polish market. Flows then recovered and stabilised in June, and it appeared that 'normal service had been resumed', albeit at a lower level than in previous years.

This new strategy was confirmed by the outcome of an auction held by the Polish TSO, Gaz-System, on July 6, when entry capacity at Kondratki totalling 817 GWh/d, which equates to 76 mmcm/d, or 78 per cent of Yamal-Europe's 97 mmcm/d technical capacity, was offered for the period October 1 2020 to October 1 2021. At the auction, 99.997 per cent of the capacity on offer was purchased, one must assume by Gazprom, given that it is the monopoly supplier of gas to Belarus, and the only entity capable of physically delivering gas from Belarus to Poland at Kondratki. As a result it seems that around 80 per cent of Yamal-Europe will be filled with Russian gas in the short to medium term. Gazprom of course also retains the flexibility to bid for the additional 20 per cent of capacity that remains free on a short-term basis, in case demand for its gas surges, but for the time being it would appear to have settled on a lower figure as being adequate to balance its needs through 2021.

Indeed, in the very short term, with Nord Stream due to shut down for maintenance from July 14-16, the Yamal-Europe pipeline will likely see a rise in physical flows. The new transit arrangement means that Gazprom will be able to utilise its existing pre-booked capacity and bid for additional daily capacity to meet any increased demand due to the unavailability of Nord Stream. As a precursor to the Nord Stream maintenance, scheduled maintenance work was carried out at Mallnow on the Polish-German border, which temporarily reduced Yamal-Europe flows to zero from July 6-10. However, with Nord Stream already operating at full capacity, Gazprom compensating by drawing on storage stocks in the region.

As a result, although Gazprom has committed to a five-year transit contract with the Ukrainian TSO, GTSOU (Gas Transmission System Operator of Ukraine), the company would seem to have a clear plan to take advantage of the flexibility offered by the capacity booking platform that has superseded its previous long-term transit contract with Gaz-System in Poland.

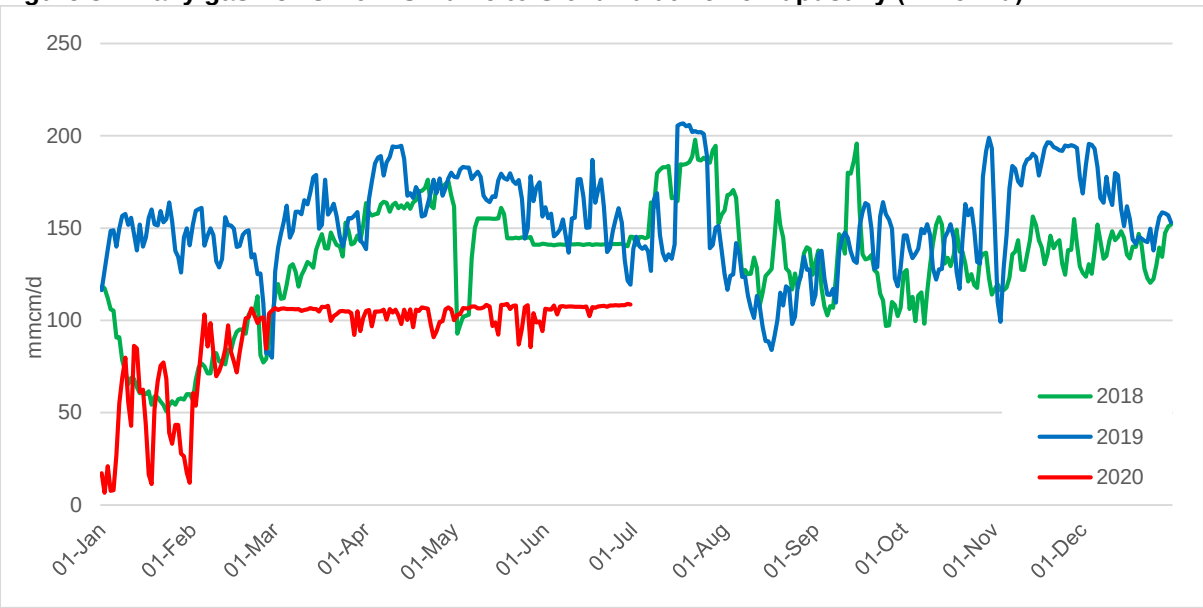
Velké Kapušany (Uzhgorod)

The new, five-year transit contract agreed between Gazprom and GTSOU includes a ship-or-pay commitment of 178 mmcm/d in 2020 and 110 mmcm/d in 2021-24. While that impacts several interconnections on Ukraine's western and southern borders – including Drozdovichi to Poland, Beregovo to Hungary, and Isaccea to Romania – the interconnection with the largest (historic and current) flows is Velké Kapušany (Uzhgorod) on the Ukraine-Slovakia border.

The interconnection at Velké Kapušany saw dramatic fluctuations in January-February, but since the beginning of March flows have stabilised at around 105 mmcm/d. This is clearly well below the contracted capacity for 2020, but is close to the committed level for 2021-24, perhaps indicating that once the exceptional circumstances of 2020 are over Gazprom is committed to using the Ukraine system as originally planned. In the longer-term, though, flows at Velké Kapušany are likely to be influenced by the launch of Nord Stream 2. Specifically, if Nord Stream 2 is completed, and volumes delivered via Nord Stream 2 are delivered via the EUGAL pipeline to the German-Czech border, and onwards to Slovakia and Austria, this could potentially displace volumes destined for Slovakia, Austria,

and Italy that are currently delivered via Velké Kapušany. Such a scenario would replicate the 'two pipeline flexibility option' that Gazprom has for delivering gas to the Gaspool market area using Nord Stream and Yamal-Europe

Figure 3.4 Daily gas flows from Ukraine to Slovakia at Velké Kapušany (mmcm/d)

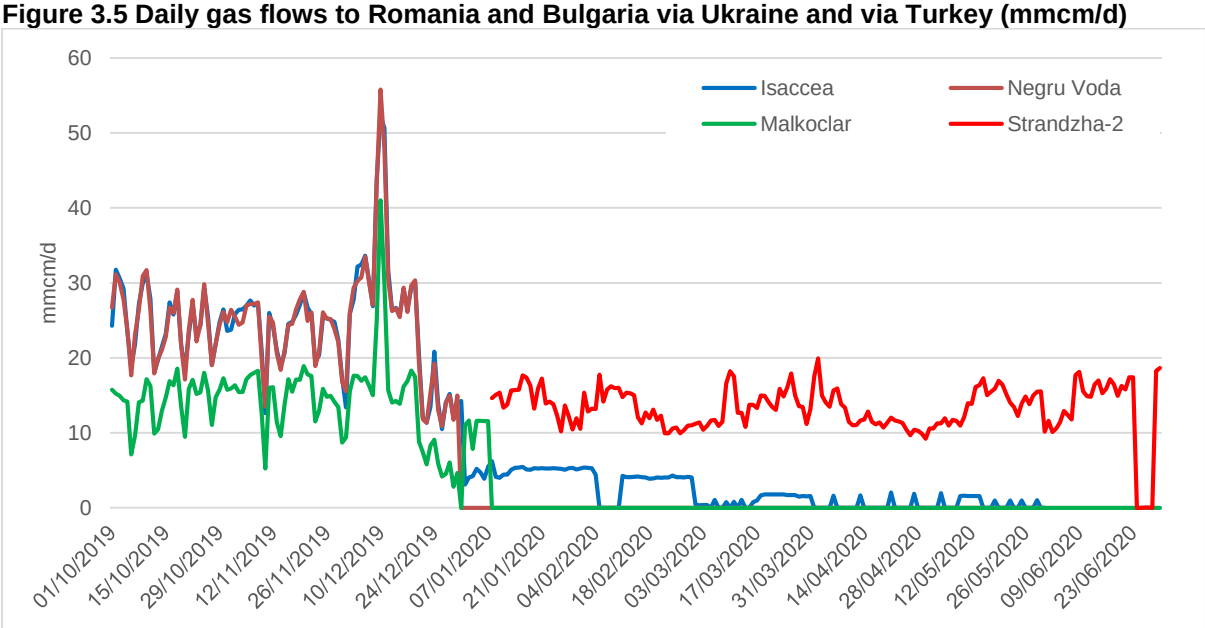


Data source: ENTSOG Transparency Platform

TurkStream

January 2020 saw the launch of the TurkStream pipeline from Russia to Turkey, and the Strandzha-2 interconnection to bring TurkStream gas across the border from Turkey to Bulgaria. Previously, the Trans-Balkan Line brought Russian gas from Isaccea on the Ukraine-Romania border to Malkoclar on the Bulgaria-Turkey border. The mid-point of the Trans-Balkan line is Negru Voda, on the Romania-Bulgaria border.

Figure 3.5 Daily gas flows to Romania and Bulgaria via Ukraine and via Turkey (mmcm/d)



Data source: ENTSOG Transparency Platform

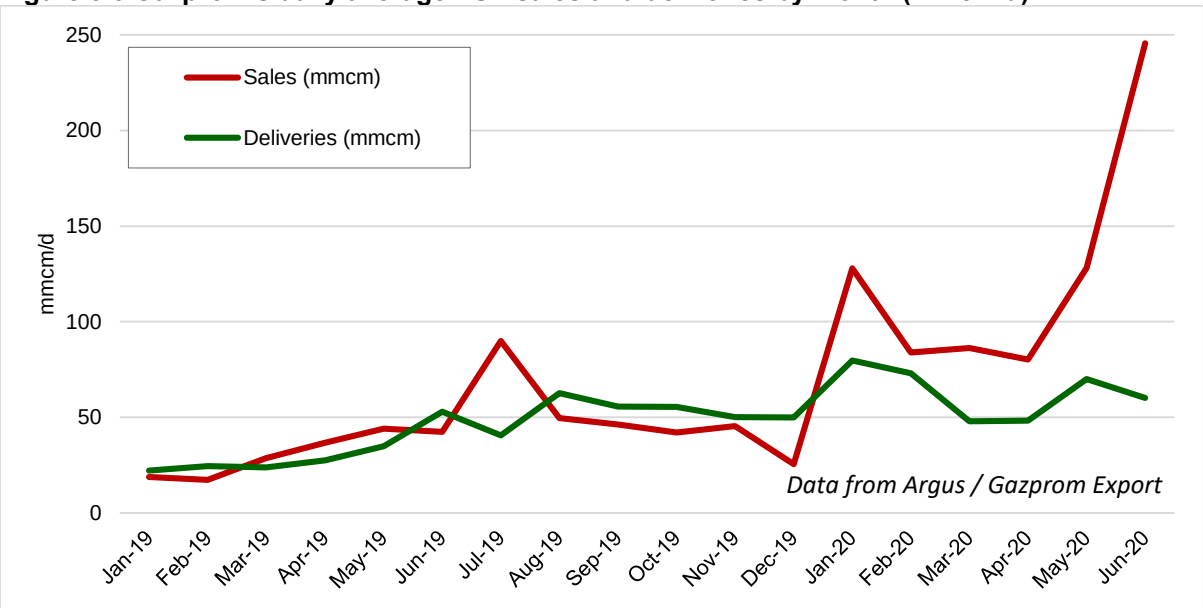
The fact that flows at Negru Voda dropped to zero in January shows that Bulgaria no longer receives gas via the Trans-Balkan Line; that line now only supplies Romania. The knock-on effect is that flows further down the line, at Malkoclar, also dropped to zero. The flows to Bulgaria via TurkStream and Strandzha-2 have fluctuated between 10 and 20 mmcm/d, which is similar to the range of flows to Bulgaria via the Trans-Balkan Line in 2019 (that is, flows at Negru Voda minus flows at Malkoclar). The drop to zero from June 24-28 was due to scheduled maintenance on the TurkStream pipeline.

There is substantial available capacity at Strandzha-2, which will be used by volumes destined for Serbia and Hungary, once the onward pipelines in Bulgaria and Serbia are complete, and the new interconnection on the Serbia-Hungary border is also complete. The construction contract for the Bulgaria section has a deadline of May 2021, while the Bulgarian and Serbian governments have publicly stated that they expect their sections to be complete by the end of 2020. In June, the Hungarian regulator, MEKH, approved the latest 10-year development plan by the Hungarian TSO, FGSZ, which states that the interconnection on the Serbia-Hungary border is scheduled to be launched by October 1 2021 with 6 bcma of capacity, rising to 8.5 bcm by October 1 2022.

Gazprom's Electronic Sales Platform

Beyond the discussion on the flow of physical supply via various pipeline routes, it is also interesting to note the increasing role of the ESP as part of Gazprom's export strategy. The ESP was launched in September 2018, and its sales volumes have grown steadily along with the variety of product types. For four consecutive months from February to May 2020, total sales volumes were between 2,400 mmcm and 2,700 mmcm. Sales then surged to 4,912 mmcm in June, helped by 1,095 mmcm of sales to Hungary as part of their new, flexible, sales arrangement that partially replaces the previous long-term contracts. Even without the sales to Hungary, ESP sales in June were up by 1,256 (+49 per cent) from 2,560 mmcm in May.

Figure 3.6 Gazprom's daily average ESP sales and deliveries by month (mmcm/d)



Source: Data from Argus and Gazprom Export

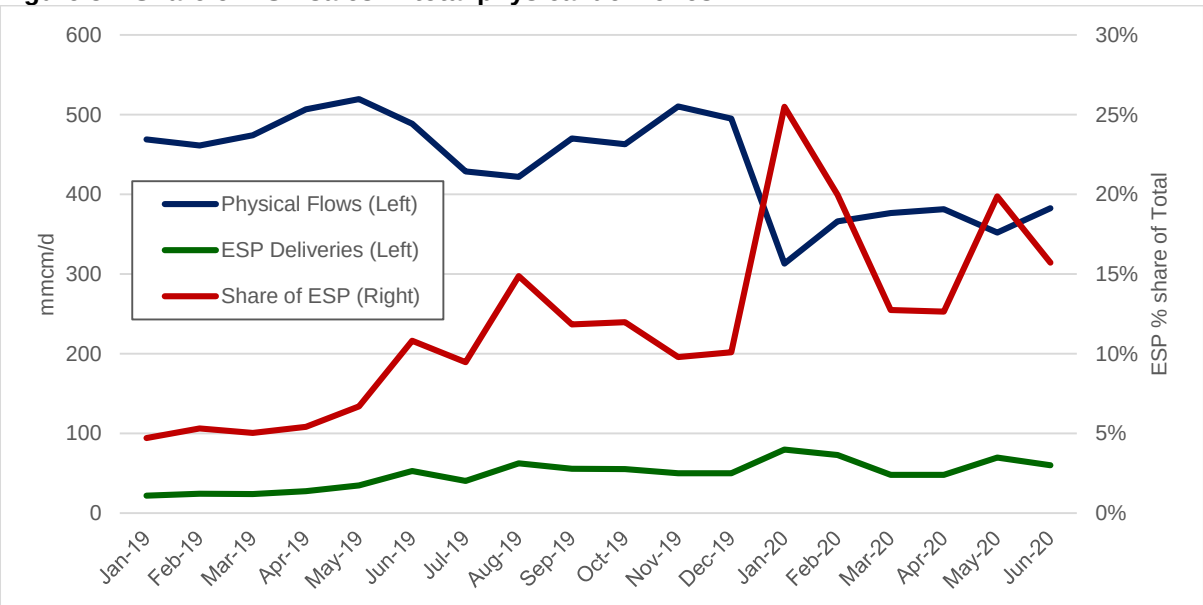
What is particularly noteworthy is that while Gazprom's pipeline deliveries to Europe in H1 2020 were substantially lower than in H1 2019, Gazprom's sales via its ESP were substantially higher. In H1 2019, Gazprom's ESP sales averaged 950 mmcm per month, while in H1 2020 that average was 3,160 mmcm per month. However, it must also be noted that Gazprom Export is selling increasing volumes for delivery further into the future from the transaction date. While sales in the first year of the ESP's operation were generally no more than up to month+3, volumes were recently sold for delivery as far out as summer 2022.

Indeed, in every month between October 2018 and February 2020, sales for prompt, balance-of-month, and month+1 accounted for between 74 and 100 per cent of total sales, at an average of 89 per cent of the total. In Q4 2019, such sales accounted for 99 per cent of the total, falling to 89 per cent in January 2020 and 79 per cent in February. However, that figure collapsed to 24 per cent in March, recovered to 53 per cent in April, and fell again to 31 per cent in May, a month in which just under half of total sales were for more flexible delivery in Q3 2020. Then, in June, for the first time, there were zero sales for prompt or balance-of-month delivery. Instead, sales for delivery in Q3 2020 accounted for 41 per cent of the total, along with sales for delivery in Q4 2020 (10 per cent), winter 2020/21 (8 per cent), and sales for delivery in the calendar year 2021 (29 per cent).

When set against a background of lower year-on-year pipeline delivery volumes in H1 2020, the general year-on-year increase in ESP sales suggests that Gazprom's LTC counterparties may have been nominating down their take-or-pay volumes in favour of low-priced purchases on the ESP, where the weighted average sales price (the ESP index) has tracked European hub prices on their downward trend. However, the decline in transactions for prompt or near-term delivery since March reflects the short-term decline in European demand. Gazprom has compensated by offering more flexible products, and in doing so has locked in sales for delivery further into the future.

Indeed, it can be argued that Gazprom's use of the ESP provides an excellent support to a pipeline export strategy which focuses on 'control and flexibility' – that is, ownership of gas transmission infrastructure outside the EU and optionality through excess capacity. To compliment this Gazprom now also has its own sales platform which it can use as an alternative to placing volumes on European hubs and is thus maintaining sales volumes through the offer of greater flexibility to its counterparties. Of course, Gazprom needs export pipeline capacity to be able to ship ESP sales to the delivery points, and in the short-term this has been provided by the reduction in the call on Russian pipeline gas in Europe. In the medium-term, such spare capacity may be provided by Nord Stream 2 and the completion of the onward sections of TurkStream, and so the rising share of ESP sales within Gazprom's export portfolio, shown in Figure 3.7 and up from 8.8 per cent in 2019 to 17.5 per cent in H1 2020, may well be set to continue.

Figure 3.7 Share of ESP sales in total physical deliveries



Source: Data from Argus and Gazprom Export

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4. Medium term impact of COVID 19 on gas markets

The April Quarterly Gas Review was largely devoted to the impact of COVID-19 on the global gas market and the possible differences between various countries and regions. The focus was purely on 2020 and the immediate impact of a short sharp hit to demand and then a sharp recovery, all over a period of 6 months. The IMF, in their April World Economic Outlook[4], had projected a 3 per cent decline in global GDP for a V-shaped decline and recovery – a base case. There were significant differences between countries and regions in the IMF outlook and, at OIES, we looked at the major countries and regions, especially those involved in the international trade in gas, to assess the potential impact on gas demand by country, the impact on gas trade and an overall assessment.

Based on the V-shaped decline and recovery, with everything largely returning to normal by the end of 2020, a fall of some 3 per cent in global gas consumption was projected in 2020 compared to 2019, which was over 4 per cent below the pre-COVID-19 case. The largest volume declines were in North America, Europe, and Russia. Consumption in China was expected to be up by just under 5 per cent in 2020 but that is some 5 per cent less than the pre-COVID-19 case. Consumption in all other regions was seen as either flat or declining in 2020 over 2019. There were significant production declines in Russia, Europe, North America, Caspian region and the ASEAN countries. LNG trade was still expected to grow year-on-year by some 5 per cent but this was well below the pre-COVID-19 case. Pipeline imports into Europe were also expected to be significantly lower, especially imports from Russia.

The analysis of the impact of COVID-19 has now been further reviewed and also extended into the medium term – the period up to 2025. The likelihood of a V-shaped decline and recovery limited to 2020 has all but disappeared and the effects seem likely to be much longer lasting. The IMF have produced another World Economic Outlook[5], which is much less optimistic regarding global GDP growth, projecting a 4.9 percent decline in 2020, 1.9 percentage points below the April 2020 World Economic Outlook (WEO) forecast. The IMF also noted that the COVID-19 pandemic has had a more negative impact on activity in the first half of 2020 than anticipated, and the recovery is projected to be more gradual than previously forecast. In 2021 global growth is projected at 5.4 percent – which broadly returns global GDP to the 2019 level, although there are significant country and regional differences.

The analysis will focus on an overall review of global consumption, Europe, China, the LNG market and gas prices. The projections through to 2025 have been generated using Nexant's World Gas Model, based on analysis of the expected levels of gas demand, with the outputs focussed on how this demand is supplied and the implications for gas prices. Comparisons will also be made with the recently published IEA Gas 2020 report[6], based on the text and the charts in the report.

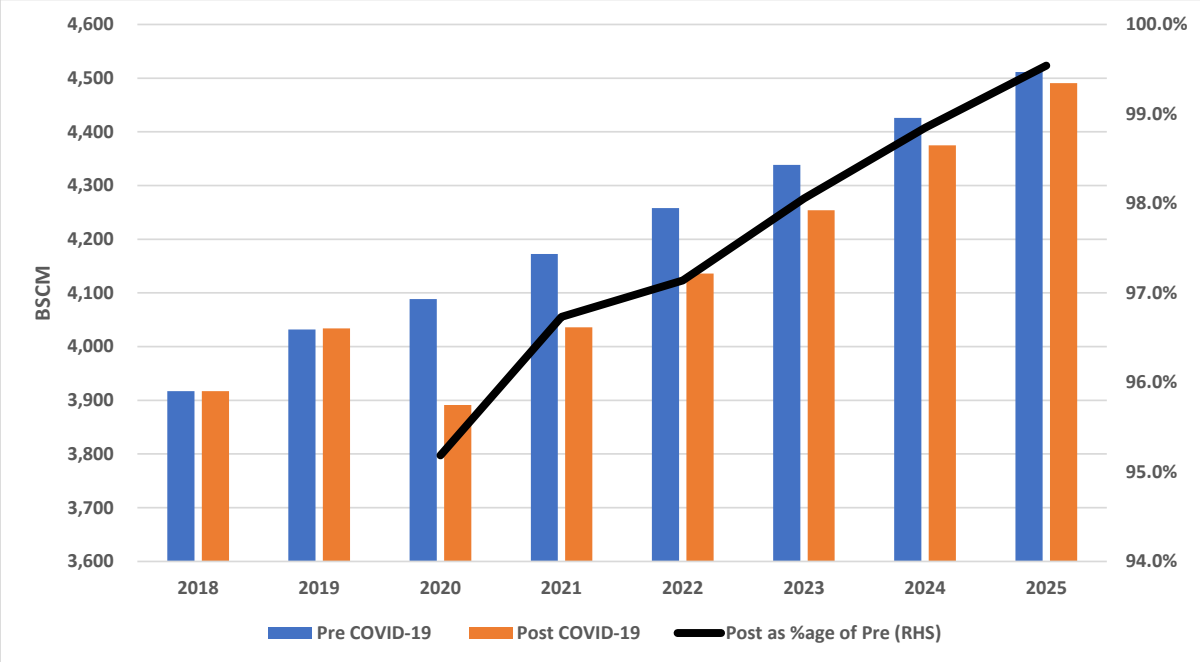
Global Gas Demand

According to our model, global gas demand is projected to be lower by some 140 bcm in 2020 compared to 2019 – a decline of some 3.5 per cent. This is somewhat less than the projected decline in global GDP by the IMF. Gas demand in power in some countries is holding up better than expected, notably in the US and some European countries, as coal takes a bigger hit from COVID-19 than gas, in part because of very low gas prices. Gas demand is also still growing in China and showing signs of recovery in other Asian countries.

In 2021, gas demand rebounds by 3.7 per cent, returning to 2019 levels. However, this is still over 3 per cent lower than our forecast in the Pre-COVID-19 case. Thereafter, annual gas demand growth is over 2.5 per cent, with demand just about returning to pre-COVID-19 levels by 2025. While overall global GDP may still be lower by 2025 than a baseline pre-COVID-19 scenario, gas demand in some countries may be supported by continued low gas prices, especially in some of the faster growing Asian markets.

[4] IMF World Economic Outlook, April 2020, at https://www.imf.org/en/Publications/WEO/Issues/2020/04/14/weo-april-2020
[5] IMF World Economic Outlook, June 2020, at https://www.imf.org/en/Publications/WEO/Issues/2020/06/24/WEOUpdateJune2020
[6] IEA Gas 2020, June 2020, at https://www.iea.org/reports/gas-2020

Figure 4.1: Global Gas Demand to 2025

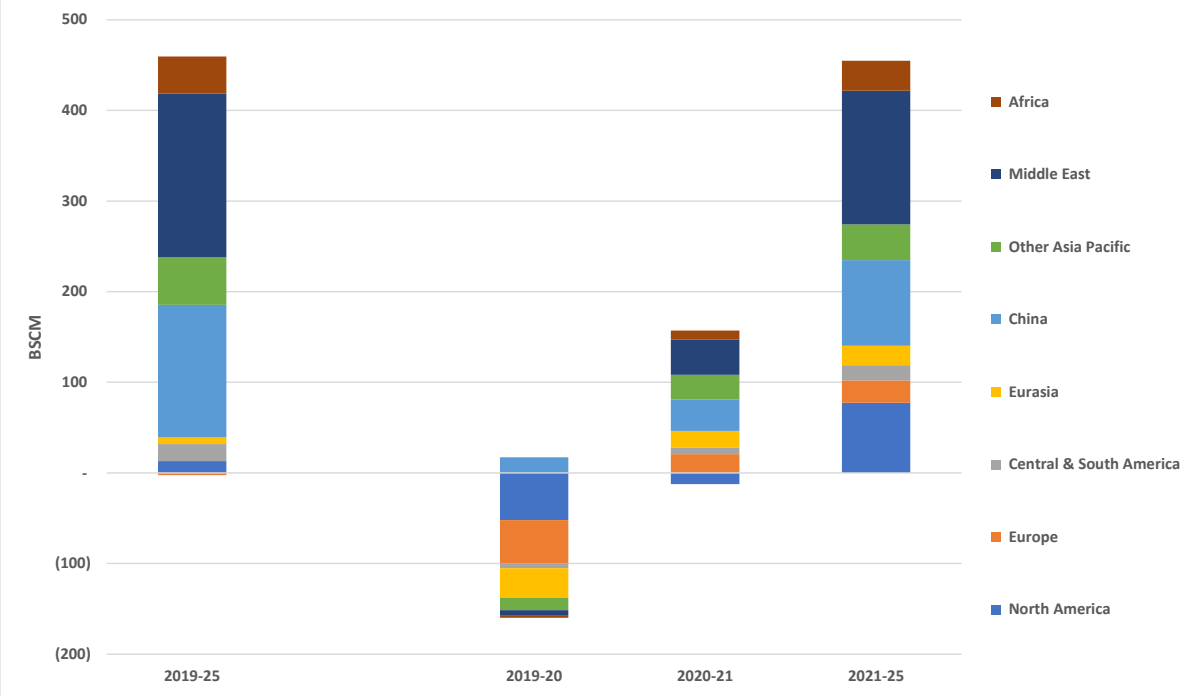


Source: IEA, Nexant World Gas Model, OIES Analysis

Based on the latest IMF GDP outlook, the largest falls in gas demand in 2020, both in percentage and volume terms, will be in Europe, North America and Russia. Europe declines by some 8.5 per cent – almost 50 bcm. Gas demand in China, on the other hand continues to grow by 5.5 per cent or 17 bcm, more than offsetting declines in the rest of Asia. In 2021, China demand growth soars by some 35 bcm (14 per cent), while demand in the rest of Asia Pacific also rebounds, including in Japan. Growth in the Middle East also resumes, but demand remains weak in North America, as gas in power stalls. Meanwhile in Europe the rebound in 2021 will recover less than half the loss expected in 2020.

Post 2021, China, the Middle East and North America drive the growth in volume terms, followed by the rest of Asia Pacific. Europe just about returns to the 2019 level of gas demand by 2025 – around 550 bcm. China in the meantime has grown by almost 150 bcm between 2019 and 2025, the rest of Asia Pacific by over 50 bcm and the Middle East by 180 bcm.

Figure 4.2: Regional Breakdown of Changes in Demand to 2025



Source: IEA, Nexant World Gas Model, OIES Analysis

The IEA, in Gas 2020, which was published before the latest IMF scenarios, also shows gas demand in 2021 recovering the demand lost in 2020, returning to 2019 levels. However, thereafter, gas demand growth is slightly slower than our projection and gas demand does not return to the pre-COVID-19 projected demand by 2025. Demand growth between 2019 and 2025, according to the IEA, is just under 400 bcm, whereas our projection suggests growth of 450 bcm. The key difference would appear to be the growth in the Middle East, where we are more bullish. Excluding the Middle East, we have growth of 275 bcm between 2019 and 2025, while the IEA, from its charts in Gas 2020, would look to be around 260 bcm.

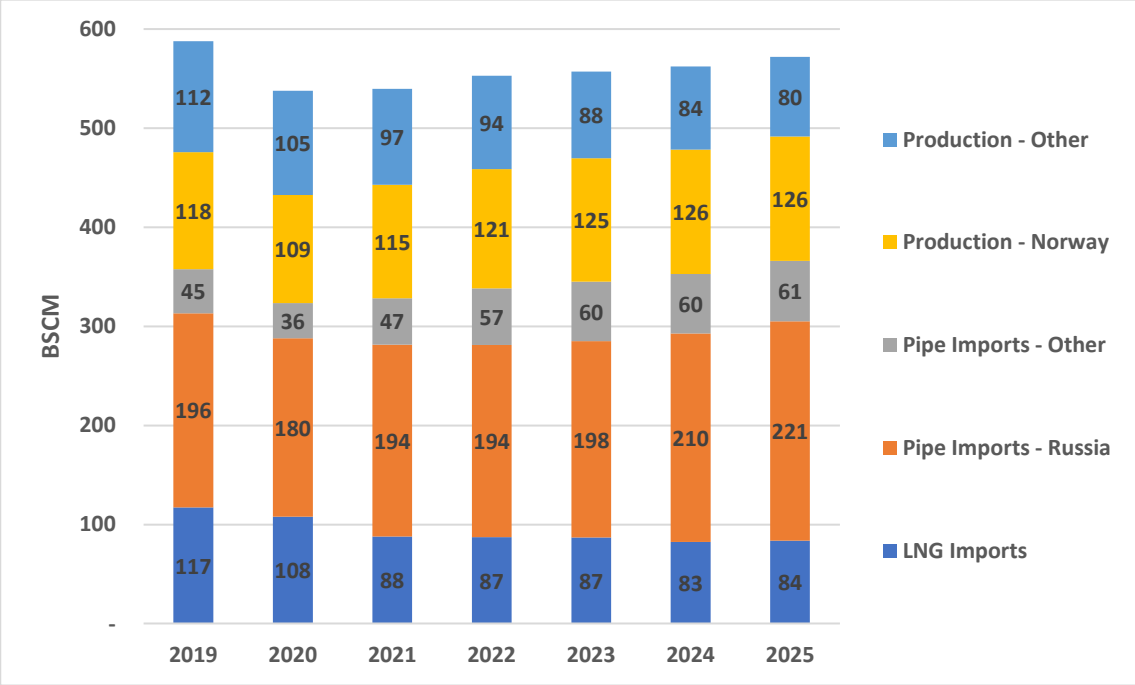
Europe[7] Balances

Europe demand is forecast to decline to some 505 bcm in 2020 – down from 550 bcm in 2019 – before recovering to 525 bcm in 2021, reaching 550 bcm again in 2025. The 2020 decline in demand squeezes all sources of supply, including LNG imports, while our previous projection back in April had shown LNG imports possibly even increasing in 2020 over 2019. This change reflects the fact that total European demand this year is lower than previously estimated. While demand rebounds somewhat in 2021, on the supply side it is expected that pipe imports from Russia increase significantly, with Nordstream 2 coming online, and also Azeri volumes picking up, as the Trans-Adriatic pipeline comes on stream. Norway production also recovers somewhat. This suggests that LNG imports could fall quite sharply in 2021, but that may depend on demand for LNG in Asia and also the extent to which storage utilisation in Europe declines. Europe could still accommodate a lot more LNG in 2021 than the 88 bcm suggested in our projection but that would imply storage again largely filling in the summer months – this is discussed further in the LNG Trade section.

Post 2020, Norway production grows, as do pipe imports, especially from Russia in 2024 and 2025. LNG imports are maintained between 80 and 90 bcm. By the time 2023 and 2024 is reached, LNG is being pulled away from Europe as global LNG demand outstrips supply and Asia's requirements need to be met.

[7] EU27 plus UK, Norway, Switzerland, Serbia, Bosnia-Herzegovina, North Macedonia, Albania and Turkey

Figure 4.3: European Natural Gas Supply to 2025



Source: IEA, Nexant World Gas Model, OIES Analysis

The IEA's Gas 2020 suggests that Europe gas demand recovers very little from the 2020 dip and is below 2019 levels even in 2025. However, its import requirement seems to rise more than in our projection, reflecting both weaker Norway production and lower output from the rest of Europe as well. The IEA suggests somewhat lower pipe imports from Russia and higher LNG imports, from 2021 onwards, of around 90 bcm a year through to 2025 – some 10 bcm or so higher than our projection.

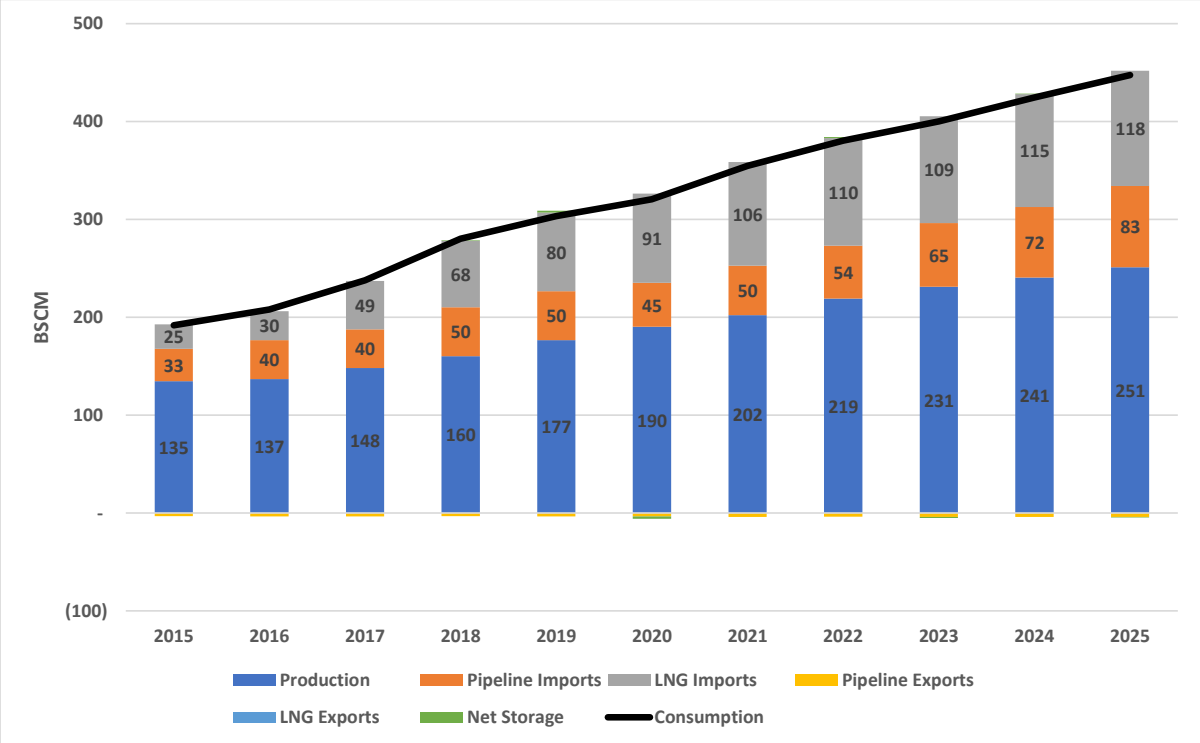
China Balances

Gas demand has held up well in China, and it will be one of the few countries to experience actual demand growth in 2020. Apparent demand was some 7 per cent higher in January to May 2020 over the same period in 2019[8]. However, this seems to overstate the robustness of gas demand, since it is thought that some of this apparent demand ended up in gas storage. Nevertheless, overall growth for 2020 is expected to be some 6 per cent, with demand rising to 320 bcm in total compared to 303 bcm in 2019. Strong growth is expected in 2021, with demand reaching some 355 bcm – an increase of 11 per cent, principally driven by growth in the industrial sector, which is the largest gas consumer in China, as the economy recovers. Growth is expected to continue apace through to 2025 with total demand reaching just under 450 bcm – an increase of almost 150 bcm over 2019 levels (7 per cent per annum growth).

Growth in China's gas production has also been strong this year, and this is expected to continue for a couple of years before slowing. Overall production grows by some 75 bcm between 2019 and 2025, which leaves almost another 75 bcm to be filled by imports. LNG should benefit from this, but regas terminal additions will need to continue as planned in order to allow new supply to arrive. At the same time the ramp up of volumes from Russia along the Power of Siberia pipe slows the growth of LNG imports, especially in 2022 and 2023. Total pipeline imports reach 83 bcm in 2025, against 50 bcm in 2019. LNG imports reach 118 bcm in 2025 against 80 bcm in 2019.

[8] Source: Argus Direct

Figure 4.4: China Natural Gas Supply to 2025



Source: IEA, Nexant World Gas Model, OIES Analysis

The IEA's Gas 2020 expects China to add some 130 bcm of incremental demand between 2019 and 2025, which is somewhat lower than our projection of just under 150 bcm. The IEA expects a 54 bcm growth in domestic production, which is 20 bcm less than our projection. The supply gap for imports, therefore, increases by 76 bcm according to the IEA, which is the same as the rise in the supply gap in our projection. The IEA sees growth in LNG imports of some 40 bcm between 2019 and 2025, broadly the same as in our projection, so the growth in pipeline imports implicitly must be similar – although the IEA's LNG import growth pattern is smoother than ours.

LNG Trade

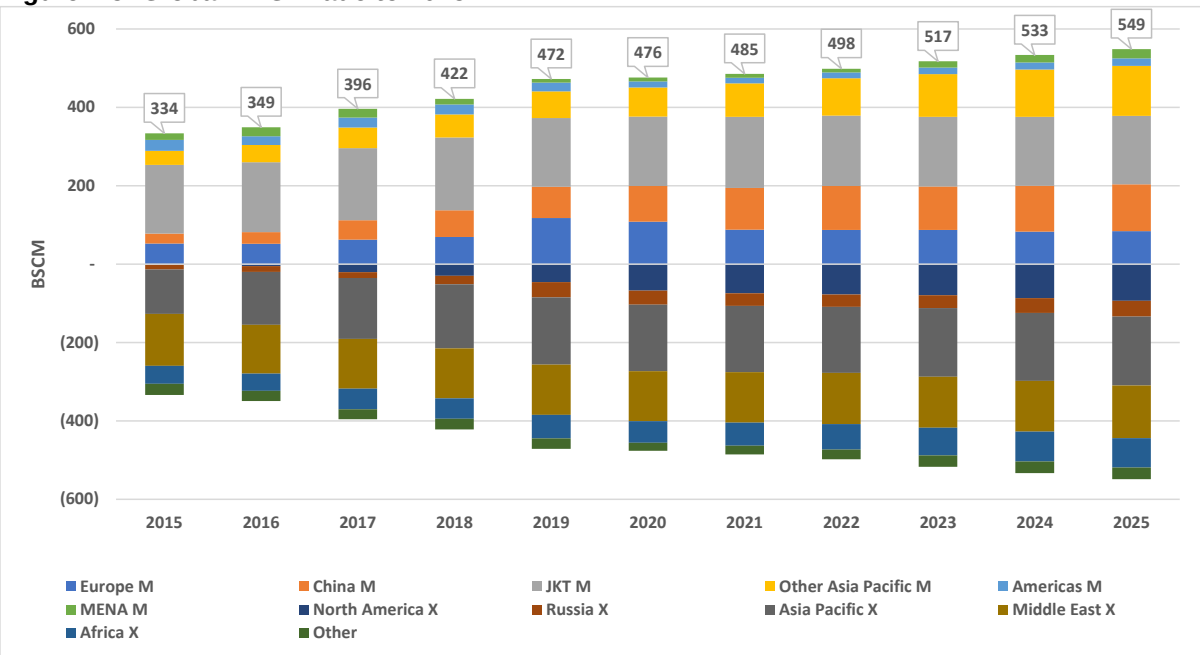
Despite the impact of COVID-19 on global gas demand in 2020, the overall level of LNG trade is expected to be slightly higher than the 2019 level, as the increase in supply continues to hit the market. However, some 20 bcm plus of LNG may still need to be shut-in in 2020 to balance the market. Looking ahead into 2021 and beyond, the growth of LNG trade depends particularly on the growth of demand in Asia and the extent to which Europe continues to absorb the excess LNG by utilising storage. Alternatively, continued low prices could necessitate more shut-ins of LNG in 2021 and possibly beyond. The figure below shows the projection for LNG trade driven by gas demand globally. This means that Europe LNG imports decline by some 20 bcm in 2021 – in effect releasing the 20 bcm "hidden" in European storage in 2019 – and remain in the 80 to 90 bcm range through 2025.

Growth of LNG imports in Asia in 2021, however, is not sufficient to absorb all the 20 bcm released from European storage in addition to the expected increase in supply. LNG imports are projected to grow by 30 bcm in the wider Asia region in 2021 – half of which is from China. Outside Asia, almost no growth is expected in LNG imports through 2023, with the Americas and MENA essentially flat overall. By 2024 and 2025 some growth is expected in Kuwait and Bahrain as their imports ramp up.

Between 2019 and 2025, total LNG imports rise by some 75 bcm, but Europe imports decline by 34 bcm, MENA and Americas rise 10 bcm, with the wider Asia region up by 100 bcm – 40 bcm from China, zero from Japan, Korea and Taiwan, and the balance from other Asian markets. On the supply side,

North America provides well over half the growth, with small increases in supply from the Middle East, Africa and Russia towards 2025.

Figure 4.5: Global LNG Trade to 2025



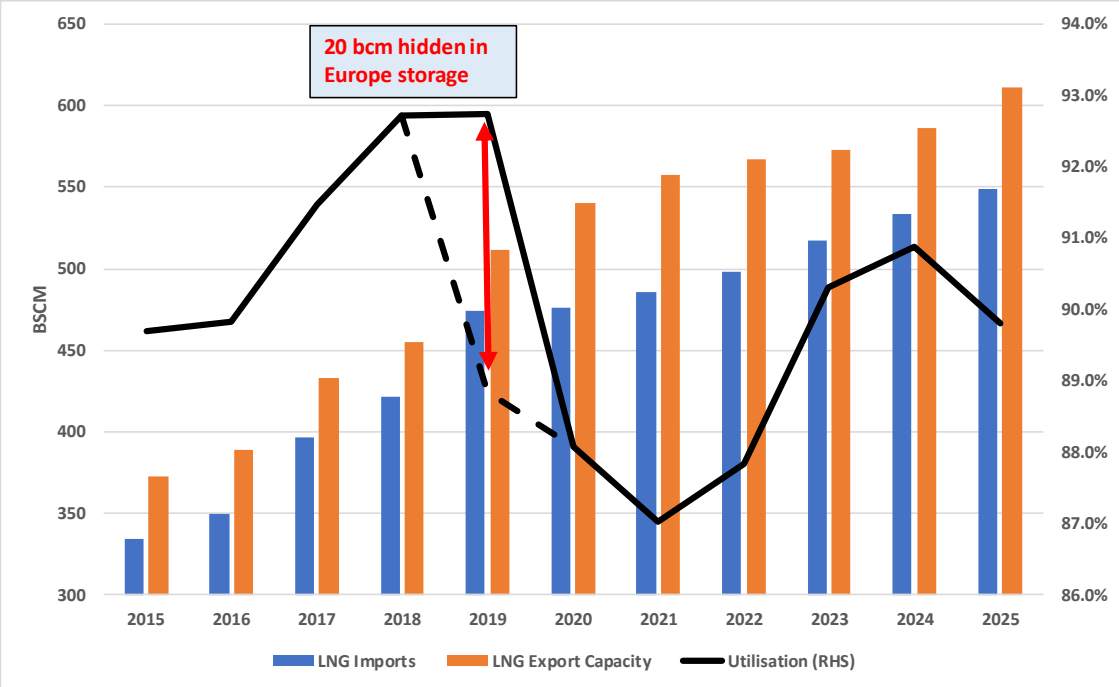
Source: IEA, Nexant World Gas Model, OIES Analysis

The IEA has higher growth in LNG trade by 2025 – "rising to just under 600 bcm" – which is some 30 to 40 bcm more than our projection. China imports are broadly similar, while the IEA has slightly higher Europe imports. The main difference would appear to be in its projection of LNG imports in other Asia Pacific markets outside Japan and Korea – mainly the emerging importers in the ASEAN countries and Pakistan and Bangladesh. The extra supply in the Gas 2020 report appears to almost all come from North America, with the US becoming the world's largest LNG exporter by 2025. By comparison, in our projections no country ever exceeds Qatar.

The growth in LNG export capacity begins to slow in 2021 and beyond as the US trains coming on ramp up to capacity. There are only a few new projects starting up in the next three years or so including the second Malaysian FLNG, Tangguh Train 3, Corpus Christi Train 3, Sabine Train 6, Tortue FLNG and Coral FLNG. The next surge in capacity is not expected to begin until late 2024 which does not have too much impact on the timeframe considered in this analysis.

The growth in trade, identified above, therefore, will begin to chip away at the level of unutilised capacity in the industry, which has risen sharply this year. The extent to which the increasing LNG export capacity is utilised depends in part how much LNG Europe absorbs. Between 2020 and 2024 (before the next wave in supply begins) available LNG export capacity is expected to rise by some 45 bcm. Over the same period of time LNG trade – based on the above figure – rises by almost 60 bcm, so the utilisation factor in LNG export plants increases. This is shown in the figure below.

Figure 4.6: LNG Export Capacity Utilisation to 2025



Source: IEA, Nexant World Gas Model, OIES Analysis

The level of utilisation in 2019 was broadly the same as in 2018 but there was a sharp drop in prices because of the growth in supply. This is because 20 bcm of LNG imports were effectively hidden in European storage and not consumed in the end-user market. Adjusting for this, utilisation fell to 89 per cent in 2019 compared to almost 93 per cent in 2018. In 2020, utilisation falls further to 88 per cent. Thereafter the outcome will depend on the growth of LNG demand in Asia and how much LNG Europe absorbs. Based purely on the projected demand in Figure 4.5, utilisation would fall again in 2021 to 87 per cent, assuming Europe did not continue to absorb the excess LNG. Alternatively, if Asian LNG demand increased by a further 20 bcm in 2021 – or if the 20 bcm in European storage didn't unwind – then utilisation would increase to some 90.5 per cent. By 2024, even with the lower projected demand, utilisation increases and, by then, is back close to 2017 levels. With higher demand the market could tighten significantly with a knock-on impact on gas prices, discussed below. However, in 2025 the next wave of LNG export capacity is coming on stream and, despite rising demand, utilisation begins to fall again.

The IEA has significantly lower levels of utilisation through 2025, despite predicting higher demand. This reflects its much higher estimate of available LNG export capacity. By 2023, the IEA's available LNG export capacity would appear to be some 25 bcm or so higher than our assumption and by 2025 maybe some 60 bcm or so higher. Some of these differences, especially by 2025, may reflect the timing of the start-ups of the next wave of LNG projects. We have pushed back the start-up of a number of the projects which have already taken FID.

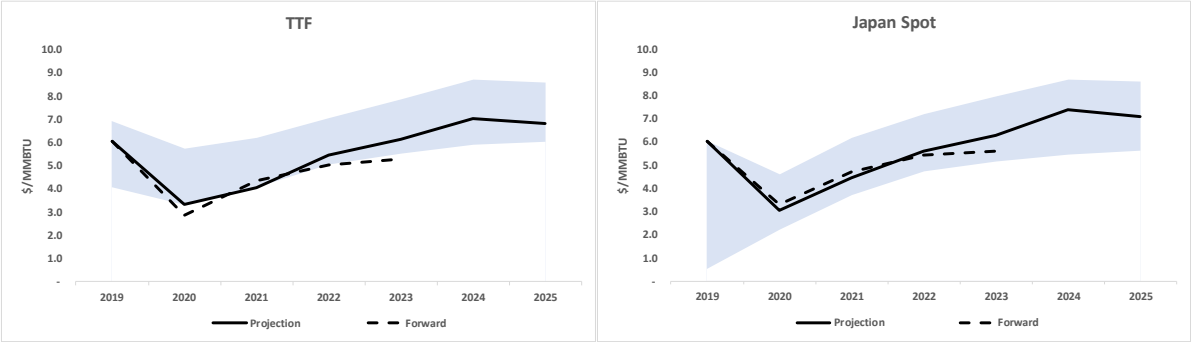
Prices

The forward curves (as at July 10) suggest that prices for both TTF and Japan spot will increase significantly in 2021, as gas demand rises again. The Nexant World Gas Model generates projections of spot prices and these are shown in the figures below.[9] The graphs plot the forward curves and the range – from the model – in which prices could fall, depending on the state of the global gas market.

[9] Prices are in nominal or outturn prices and assume average US dollar inflation of 1.5 per cent per annum

The range floor is assumed to be the short run marginal cost (SRMC) of delivering gas to the market in question, while the range ceiling is assumed to be the long run marginal cost (LRMC).

Figure 4.7: Spot Prices to 2025



Source: Argus Media, CME, Nexant World Gas Model, OIES Analysis

Prices can go above the LRMC or below the SRMC for a number of reasons – the model is not necessarily constrained to keep prices within this range. Firstly, the model calculations of LRMC and SRMC may not accurately reflect the true marginal costs – all models are only as good as the assumptions used. Secondly, even if the marginal cost calculations are correct, prices can go above LRMC if market conditions are very tight and the gas price gets driven up to, or even above, the price of competing fuels, as happened in the LNG market following the Fukushima accident in 2011. Prices could also go below SRMC if the market gets overwhelmed by supply and, for contractual or other reasons, suppliers continue to deliver gas, even if some of them – at the margin – are not covering their variable cash costs.

For both TTF and Japan spot, the forward curve and the model projection suggest rising prices in 2021, with further rises in subsequent years until, in the case of the projection, prices start to fall again in 2025, as the next wave of sharply rising LNG supply hits the market. It is also important to note that, from a modelling perspective, the price outcome also effectively assumes that significant volumes of LNG will remain shut in, at levels broadly similar to 2020. By taking this LNG off the market, suppliers, or off-takers, effectively support rising prices. In respect of the European market, this would mean a significant fall in LNG imports and a much lower level of storage utilisation – more gas withdrawn and/or less injected. However, while prices are projected to increase, the prospect of them rising back much above $6 per MMbtu, apart from one year of market tightness in 2024, look unlikely, barring any really significant and unexpected increases in Asian gas demand.

Conclusions

Overall global gas demand is projected to fall by 3.5 per cent in 2020 over 2019. This is somewhat less than the projected decline in global GDP as forecast by the IMF, as gas demand in the power sector holds up in some countries. In 2021 global gas demand returns to 2019 levels and by 2025 we would expect almost all of the negative impact of COVID-19 to have been eliminated.

Europe's decline in demand in 2020 is worse than most of the rest of the world and the recovery in demand will be somewhat slower. Pipeline imports begin to regain their share of the European market, as LNG imports fall back sharply in 2021, with supply continuing to be shut in. China is the main bright spot in the global market with demand continuing to rise rapidly – a 50 per cent rise by 2025 over 2019. Production in China also rises but there is room for both pipeline and LNG imports to increase as well, although LNG imports could come under pressure in the next few years as Russian gas from the Power of Siberia line ramps up volumes.

Significant volumes of LNG are being shut in in 2020 and this seems likely to continue in 2021 and 2022, notwithstanding the anticipated recovery in demand in the key Asian markets, as LNG export capacity has risen sharply in 2019 and 2020. Even if demand for LNG is higher in 2021 than in 2019, there is a lot more supply on the market to be absorbed.

Europe could continue to absorb some of the excess LNG by filling storage each summer, but this would be likely to result in continued depressed prices. If, on the other hand, the excess LNG gets shut in, then prices could recover, in line with the current forward curves and our model projection. However, we may only see $6 gas again when the market tightens in 2024, before the next surge of LNG export capacity arrives.

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5. Eastern pointers from the Gazprom AGM

For followers of Gazprom the months of May and June can usually provide interesting information about the company's thinking in the run-up to the Annual General Meeting, which is held at the end of June each year. In advance the company usually holds a series of press conferences at which senior management review performance but also outline strategic thinking in a number of areas – the domestic market, exports, finance, liquids, the power sector and more recently the Asian market. However, this year one of the impacts of COVID 19 has been the cancellation of these briefings and so instead we have to rely on some comments from company CEO Alexei Miller in the aftermath of the AGM,[10] combined with other snippets in the press. Nevertheless, some clear conclusions can be drawn, not least about the company's increasingly strong desire to diversify its sales in an easterly direction.

Miller's interview

After the conclusion of the AGM Alexei Miller gave an interview to the in-house Gazprom magazine in which he was asked about his highlights for 2019. In first place he put the continued development of the Yamal peninsula, focussing on the start of development work at the 2 trillion cubic metre Kharasaveye field, located to the north-west of the already producing super-giant Bovanenkovskoye. Production is targeted to start in 2023, with an ultimate plateau of 32bcma that could send gas west to Europe or potentially east to Mongolia and China.

Secondly, Miller cited the successful completion of another winter of reliable supply to the Russian people and economy, underlining the political and social importance of the company. In third place, though, he mentioned two export projects, Turk Stream and Power of Siberia, which came into operation during the year, underlining the long-term strategic importance of the latter for relations with China. Indeed, he further underlined the importance of eastern investment in his fourth highlight, announcing that the Amur processing plant, which is essential to the ultimate success of Power of Siberia, is now more than half finished. In fifth place he then put the company's financial performance and its ability to maintain its dividend in a challenging year.

Interestingly he was then asked if the financial challenges would affect the company's investment plans, at which point he spent much of the rest of the interview focusing on the company's eastern business. The importance of the Amur processing plant was reiterated as it is a vital cog in the objective to ramp up output through the Power of Siberia line over the next four years. The plant will strip valuable by-products such as ethane, propane and butane from the gas stream (with helium having already been removed and reinjected at the field), with the first 14bcm of capacity being commissioned in 2020 and the full capacity of 42bcma being reached by 2024. This will allow methane exports to China to reach their initial goal of 38bcma by 2025.

In the meantime, the capacity of Power of Siberia is being increased with investment in a series of compressor stations over the next few years, with $1.1 billion being spent this year on the second of nine.[11] Equally importantly, though, investment is also starting in the 2.7 tcm Kovycta field, which will support production from the Chayanda field which is currently supplying Gazprom's exports to China. Like Chayanda, Kovykta will have an initial peak of 25bcma, although this could rise if further layers of the field are developed. Construction of an 800km pipeline to Chayanda is now underway, and 31 production wells are being drilled in 2020 as part of the plan to get production underway by late 2022, providing more than enough gas to meet the initial contract requirements with China.[12]

Further plans to meet strategic goals

While the 38bcma objective for 2025 exports coincides with the short-term goals of the Russian government, the longer-term aspiration is for continued growth. The recently published Russian Energy Strategy cites a target of 80bcma of exports to China by 2035,[13] but Gazprom's Alexei Miller has been

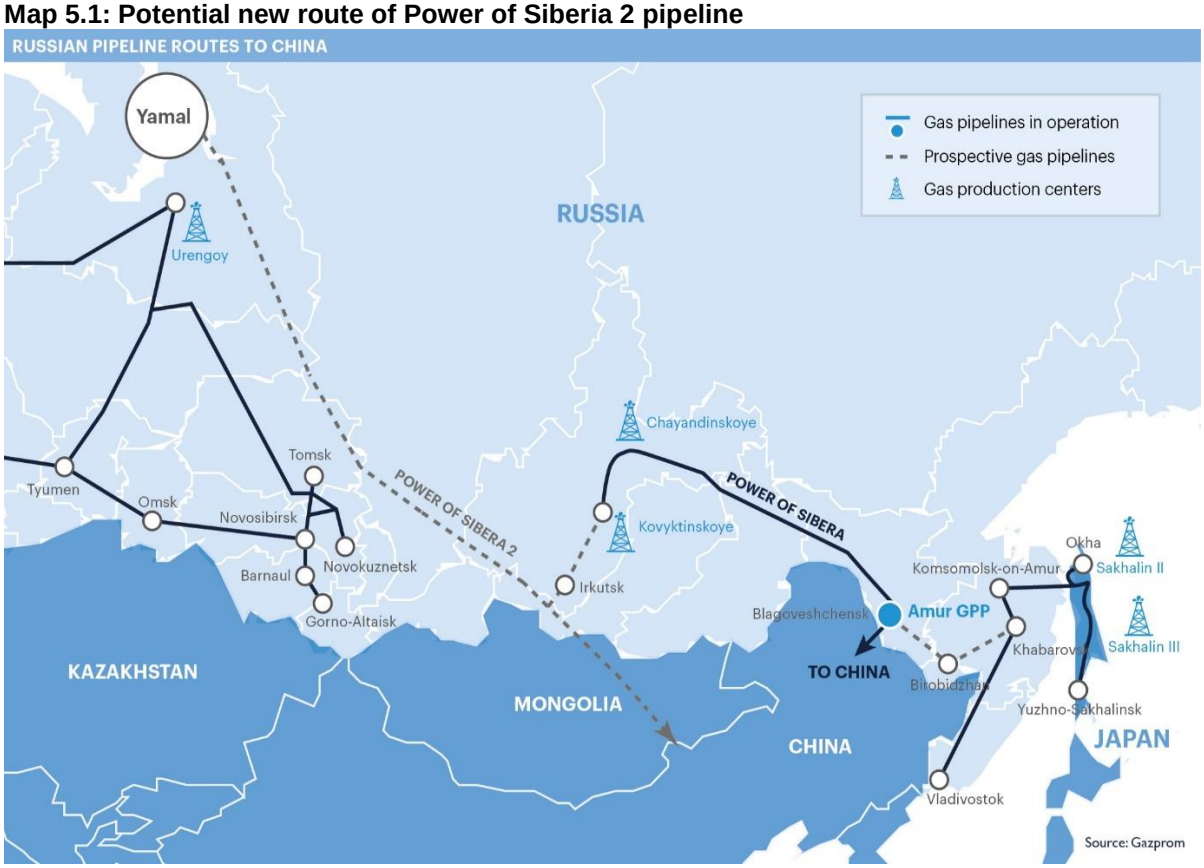
[10] Interview with Alexei Miller on Gazprom website at https://www.gazprom.com/press/news/miller-journal/2020/459926/
[11] Argus Media 14 April 2020, "Gazprom presses on with PoS1 plans"
[12] Argus Media 23 March 2020, "Kovykta gas development advances"
[13] Argus Media, 17 April 2020, "Russian gas strategy focuses on China"

even bolder in his statements, looking for pipeline gas exports from Russia to its eastern neighbour to reach 130bcm at some stage.

Initially the growth may come from an expansion of the capacity in the existing Power of Siberia line. Miller noted in his interview that negotiations are already underway to increase supply by 6bcm, and it is clear that the two fields mentioned above have enough potential to meet this level. However, any further increase will need a new pipeline system, and connection to additional fields, leading back to Miller's original discussion of new developments on the Yamal peninsula. It would seem that the investment in Kharasaveye is not just about underpinning exports to Europe but is also aimed at supplying gas to China via a new pipeline system, Power of Siberia 2.

Discussions over a new pipeline system from West Siberia to China have been ongoing for more than a decade, and indeed Gazprom was originally keen to prioritise this link over the current Power of Siberia line. However, the Chinese counterparties have always been put off by the fact that the border crossing for Power of Siberia 2 has to date been targeted at the Xinjiang region of western China, many thousands of kilometres from the main consuming regions in the East.[14] It would also have put Russian gas in direct competition with supply from Central Asia for space in the West-East pipeline system within China. In the past few months, though, a major shift has occurred as the route has moved significantly eastwards with a new proposal for Power of Siberia 2 to transit Mongolia into North-East China.

Map 5.1: Potential new route of Power of Siberia 2 pipeline



Source: Gazprom

It would seem that the issue of involving a transit country, which by default increases security of supply risk, has been discounted by China and Russia, as both presumably feel that they have enough influence over Mongolia to allay any potential threat. In addition, comments from the Russian side

[14] Henderson, J. & Mitrova T. (2015) "The political and commercial dynamics of Russia's gas export strategy" Working Paper NG 102, p.17

suggest that Gazprom may also see Mongolia, whose energy economy is currently dominated by coal, as a source of future sales. The Mongolian government is under some social pressure to address air quality issues in its major towns, and especially the capital Ulan Bator,[15] with coal to gas switching in the power sector being one possible solution.

However, this potential extra demand is not enough to explain the second major change to Power of Siberia 2, namely an increase in the planned capacity from 30bcma to 50bcma. Admittedly sources inside CNPC have yet to acknowledge the possible 80 per cent increase in capacity, but Alexei Miller has now told President Putin that it is possible due to the expected growth in Chinese gas demand, and so on the Russian side at least it is a new aspiration.[16] What makes it potentially more plausible from a Chinese perspective is that the pipeline will land in China only 560km from Beijing, meaning that the cost of transport inside China will be much lower than under the previous plan. Nevertheless, it would surprise no-one if any new contract took many years to negotiate. The history of Power of Siberia showed that a first protocol on gas exports was signed by President Putin in Beijing in 2006,[17] but it was not until 2014 that a final sales agreement was signed and gas did not flow until the end of 2019. As a result, Gazprom's stated goal of exporting gas through Power of Siberia 2 by 2030 seems ambitious to say the least, with agreement on price likely to be the key stumbling block.

Current flows and prices – a double-edged sword

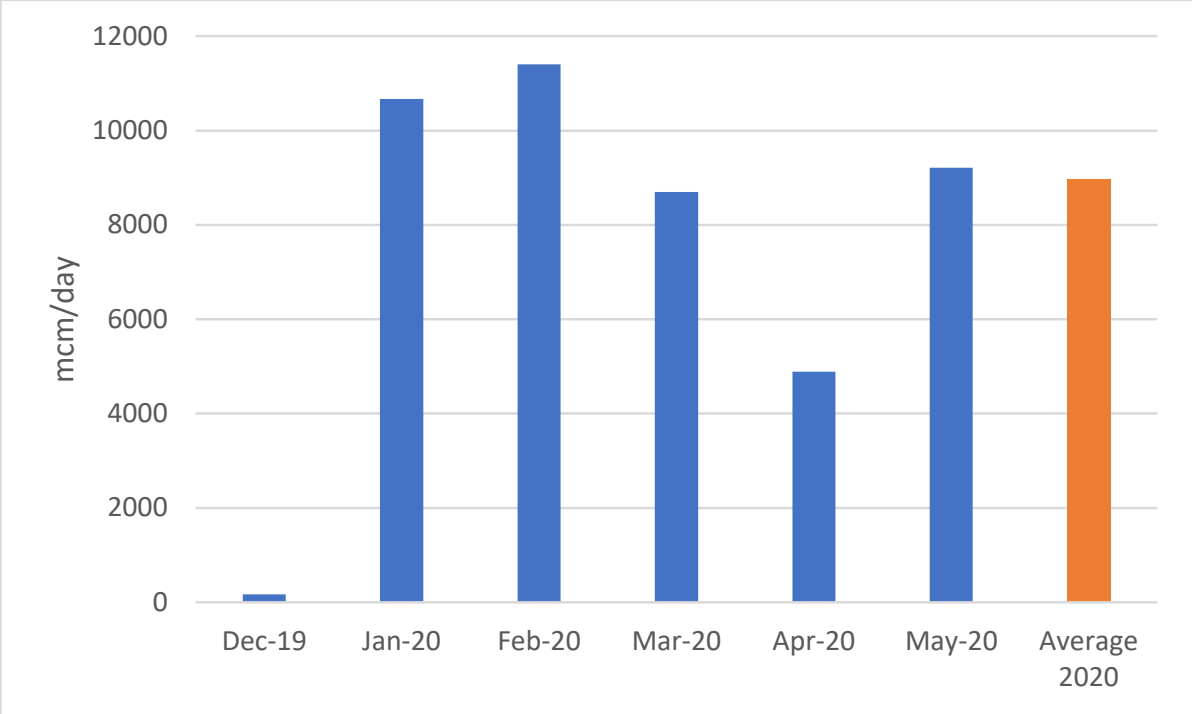
A certain level of cynicism about the future of new infrastructure from Russia to China is also supported by a review of Power of Siberia operations to date. An obvious caveat is that the pipeline has only been operating for six months, but already we can see the impact of market conditions on flows.

Figure 1 shows the average daily flow by month since December 2019. The December figure is distorted by the fact that gas did not flow for the full month, but it is clear from the 2020 data that exports are not on target to meet their 5bcm goal for the year as a whole. The current average flow is just under 9mmcm/d, equivalent to around 3.5bcm for the year as a whole, and it is clear that exports have had to respond to changing demand conditions inside China, with the falls in March and April catalysed by the impact of COVID 19. Although the declines were explained by routine maintenance on the Russian side, it nevertheless seems clear that the level of exports will realistically depend on actual demand on the Chinese side rather than on the contractual figures. 2020 is of course an extraordinary year, but the fact remains that most of the bargaining power remains with the Chinese side.

On a more positive note, though, Russian gas is certainly competitive on price in China. As Figure 2 shows, the border price of gas delivered through Power of Siberia is lower than all its competitors, although one should caveat that LNG is delivered much closer to the consumer location while Power of Siberia gas has to incur the extra cost of pipeline transport inside China, as does pipeline gas from Central Asia. Nevertheless, Gazprom would appear to have a competitive advantage, at least in the short-term. It will be interesting to see if and how this position shifts towards the end of 2020, when the impact of lower oil prices earlier in the year will be seen in oil-linked LNG contracts, but as the Power of Siberia contract is also oil-linked the relative impact may not be too severe.

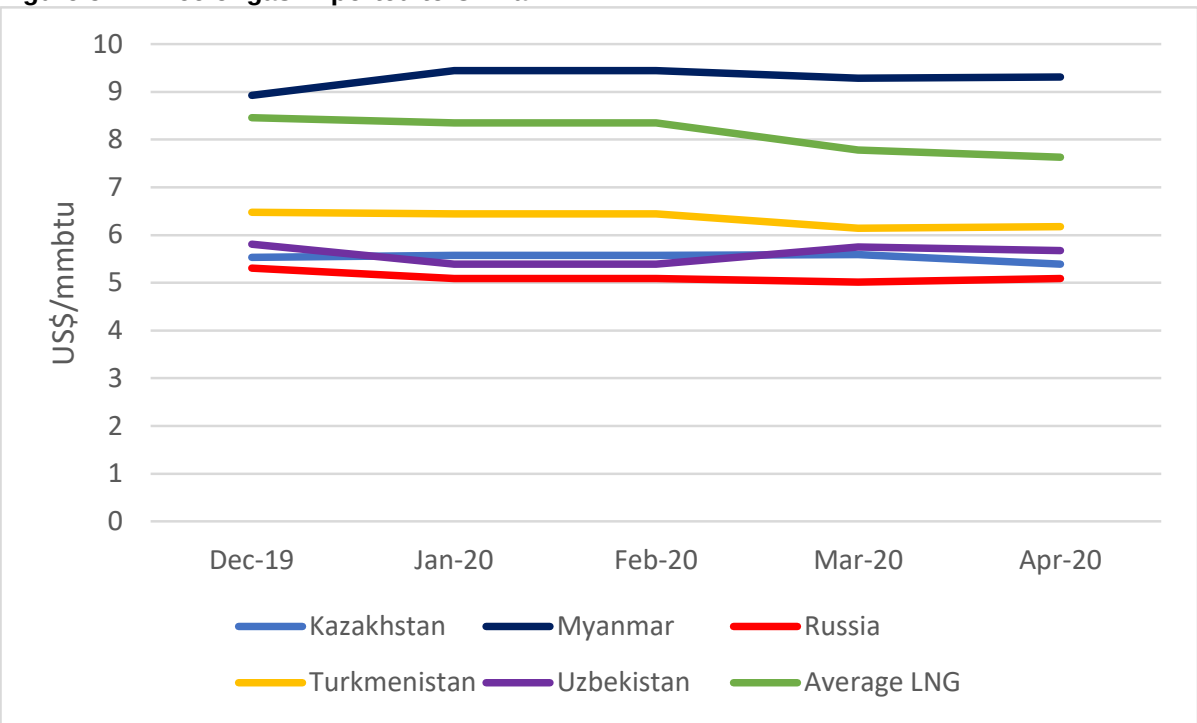
[15] Time Magazine, 23 March 2018, "Life in the most polluted capital in the world"
[16] ICIS, 30 April 2020, "GIF Inside Story: Power of Siberia's new route makes Russian gas supplies to China more feasible"
[17] Interfax, 21 March 2006, "First gas supplies to China may begin in 2011 – Miller"

Figure 5.1: Gas flows via Power of Siberia



Source: Argus Media

Figure 5.2: Price of gas imported to China



Source: Argus Media

Conclusions

Russia's "pivot to Asia" has been a strategic goal for some time now, but from a Gazprom perspective its difficulties in Europe now seem to be accelerating the desire for a shift eastwards. Indeed, the

company's Annual Report places the development of upstream and downstream infrastructure to enable growth in exports to Asia at the top of its list of strategic priorities.[18] Furthermore, the Russian Energy Strategy envisages that the vast majority of any gas export growth over the next fifteen years will come from sales of LNG and pipeline exports to Asia, with sales to Europe remaining essentially flat. And finally, Alexei Miller has been eager to underline to European customers and politicians that Russia does not plan to remain dependent on the European market for its gas exports and may soon have a balancing option in the East. Of course, this does not mean that this outcome is inevitable. As we are already seeing with Power of Siberia, Russian gas has to be price competitive with alternative sources of supply to China and will have to respond to changes in Chinese gas demand. This means that negotiations over a new pipeline, whether Power of Siberia 2 or a link from Sakhalin Island in the Far East, which has also been under discussion, are likely to be long and complex. Having said that, the change in route proposed for Power of Siberia 2 has demonstrated an increased willingness to be flexible on the Russian side which could help to accelerate negotiations. No outcome should be expected until the impact of the COVID 19 crisis has been fully absorbed and understood, but with Chinese gas demand and import requirements expected to continue to grow for the foreseeable future, and with poor relations with the US dampening the prospects for LNG imports, it is perhaps not surprising that Gazprom and the Russian government are willing to place a significant bet on expanding gas exports significantly in the East.

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[18] Gazprom Annual Report 2019, pp. 62-64