

August 2021

Quarterly Gas Review: Short-Term Outlook for Gas Markets

Introduction

In the latest OIES Quarterly Gas Review, the first section focuses on short-term gas pricing developments, discussing the renewed spike in summer prices. After the high winter prices, there was a brief return to seemingly more normal pricing levels but with demand growth remaining strong and ongoing LNG supply issues, market tightness could persist in Q3 2021 and the coming winter of 2021/22, resulting in an extended period of relatively high prices. Indeed, gas storage in Europe wasn't filling as much as might normally be expected and is currently well below 2019 and 2020 levels, coinciding also with a large fall in Gazprom's sales on the ESP. LNG margins for US LNG exports look robust over the next few months and years. Indeed, high Europe and Asian spot prices, and the high TTF prices, have not led to any significant switch back from gas to coal in the power sector, as both coal and carbon prices have also risen significantly. In this Quarterly Gas Review, we also incorporate an analysis of carbon prices and inter-fuel competition.

In the second section of the report, we take a more detailed look at two specific factors which have led to the sharp tightening of the global gas market. Firstly, we look at the astonishing rise in China's gas demand which has fed into very large rises in LNG imports, and the factors driving this demand growth. We discuss whether these factors are temporal or more structural and what they mean for 2022. Secondly, there is a detailed analysis of Russia's pipeline supply to Europe and our interpretation of Gazprom's strategy, including Gazprom's decision, so far this year, to not book substantial additional transit capacity offered by Ukraine.

If you would like to discuss any of these issues further then please contact Mike Fulwood (mike.fulwood@oxfordenergy.org) or Jack Sharples (jack.sharples@oxfordenergy.org).

Mike Fulwood

Senior Research Fellow, Gas Programme, OIES
Mike Fulwood (mike.fulwood@oxfordenergy.org)

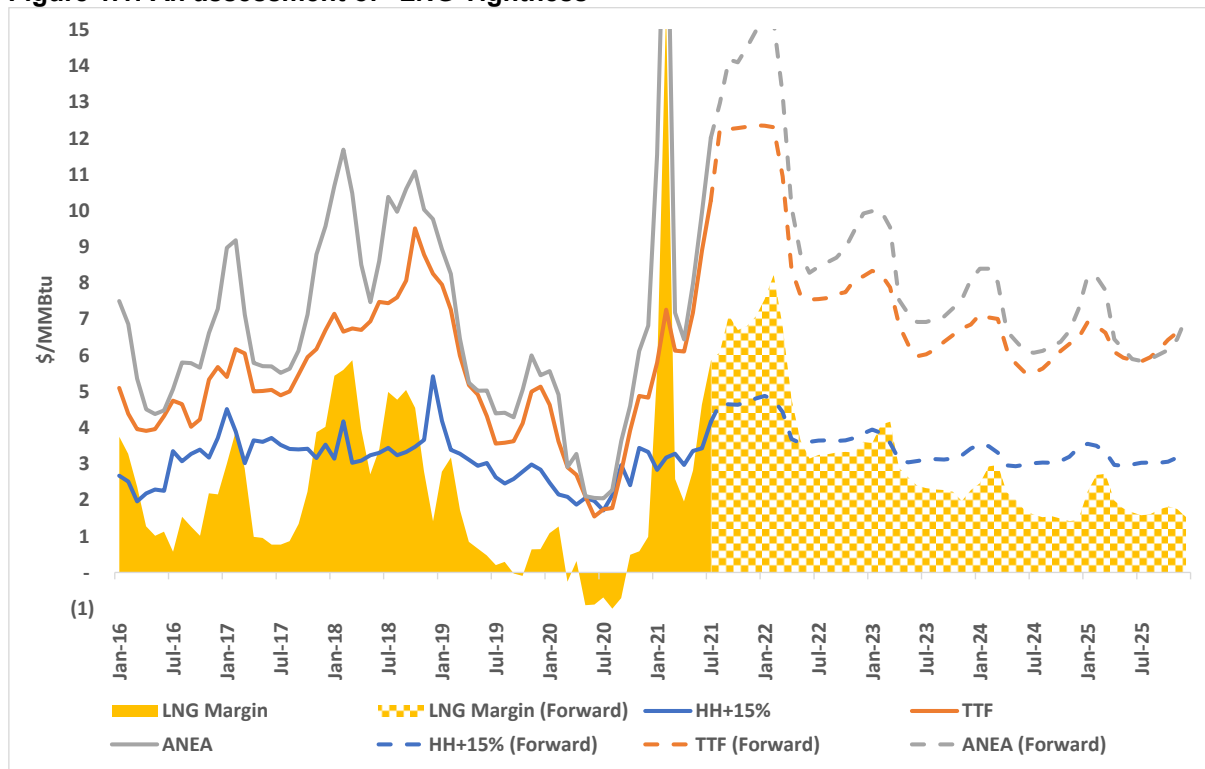
1. Price analysis

In this first section of the quarterly, we include our regular review of some key pricing trends for global LNG, Europe and Asia.

1.1 LNG tightness

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 to meet demand in the 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 in the US. It then calculates the highest netback from Europe or Asia to the US Gulf Coast plants based on the respective shipping costs. Deducting Henry Hub plus 15 per cent from the highest netback gives the LNG Margin, which provides an indication of whether developers in the US can expect to recover the fixed cost of liquefaction. A margin in excess of 3 USD/MMBtu (the fixed liquefaction cost in the traditional Cheniere contract) – 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”



Source: OIES, based on data from Argus Media. Forward curve at 23 July 2021

For the majority of 2020, when the COVID 19 pandemic caused lockdowns in Asia and Europe leading to economic decline and a fall in energy demand, the margin was negative, implying that US LNG exports were losing money on a cash basis. This led to between 150 and 200 cargoes being shut in, which started to impact the market during the summer months. However, since then the picture has changed dramatically. Initially the impact of the pandemic started to ease, and economic recovery brought higher demand and increased prices, pushing the margin back into positive territory in Q3 2020, albeit only to a level that covered cash rather than full costs. At the end of 2020 and in early 2021, the

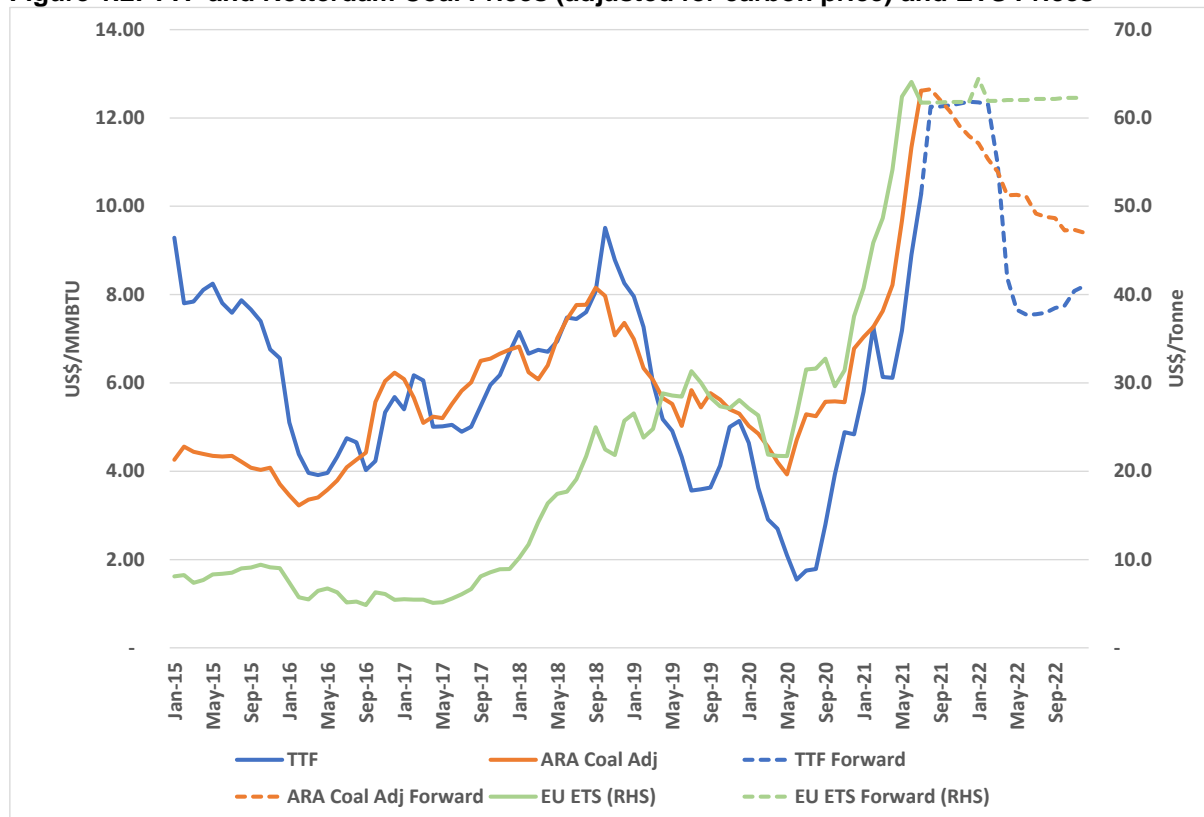
very cold weather and a dramatic rise in prices in Asia (see Figure 1.1) pushed the margin briefly to an extremely high level. The price spike in Asia was discussed in a recent OIES Comment.¹

Prices fell back quickly after the Asian spike, but the continuing tightness of the global supply demand balance has supported prices throughout the summer. Asian prices are currently ranging around 14-15 USD/MMBtu for this coming winter and TTF prices over 12 USD/MMBtu. The LNG margin, therefore, is around \$7 despite the Henry Hub forward curve being in the high \$4. While the margin remains positive, the current forward curves suggest it will fall below 3 USD/MMBtu in 2023 and below 2 USD/MMBtu by 2025. Clearly, current margins provide an incentive for new FIDs but much lower margins might not. However, going forward, margins may not be enough: Even if the economics look good, most new LNG developments will still require long-term contracts and it is not clear that the big Asian buyers are queuing up to enter into new long-term contracts, possibly preferring more flexibility.

1.2 Carbon prices and inter-fuel competition in Europe

The rising European prices, reflecting the tight global supply demand balance, might have been expected to lead to a loss of competitiveness for gas in the power market. The figure below compares TTF prices with the coal and carbon prices. The coal price (ARA) is adjusted for the relative efficiency of gas power plants to coal power plants and also the relatively higher carbon costs of coal.

Figure 1.2: TTF and Rotterdam Coal Prices (adjusted for carbon price) and ETS Prices



Source: Argus Media, ICE

In early 2019, as gas prices declined, they fell well below the adjusted coal price, and this continued in 2020 as the impact of Covid-19 put significant downward pressure on prices. As a result, there was significant coal to gas switching in 2019 and in 2020, including some lignite to gas switching in Germany. The sharp rise in TTF prices last winter, which has continued during the summer, might have been expected to lead to a significant loss of competitiveness of gas relative to coal. However, coal prices

¹ Fulwood, Mike, 2021. Asia LNG Price Spike: Perfect Storm or Structural Failure? OIES Comment, 17 February. <https://www.oxfordenergy.org/publications/asia-lng-price-spike-perfect-storm-or-structural-failure/>

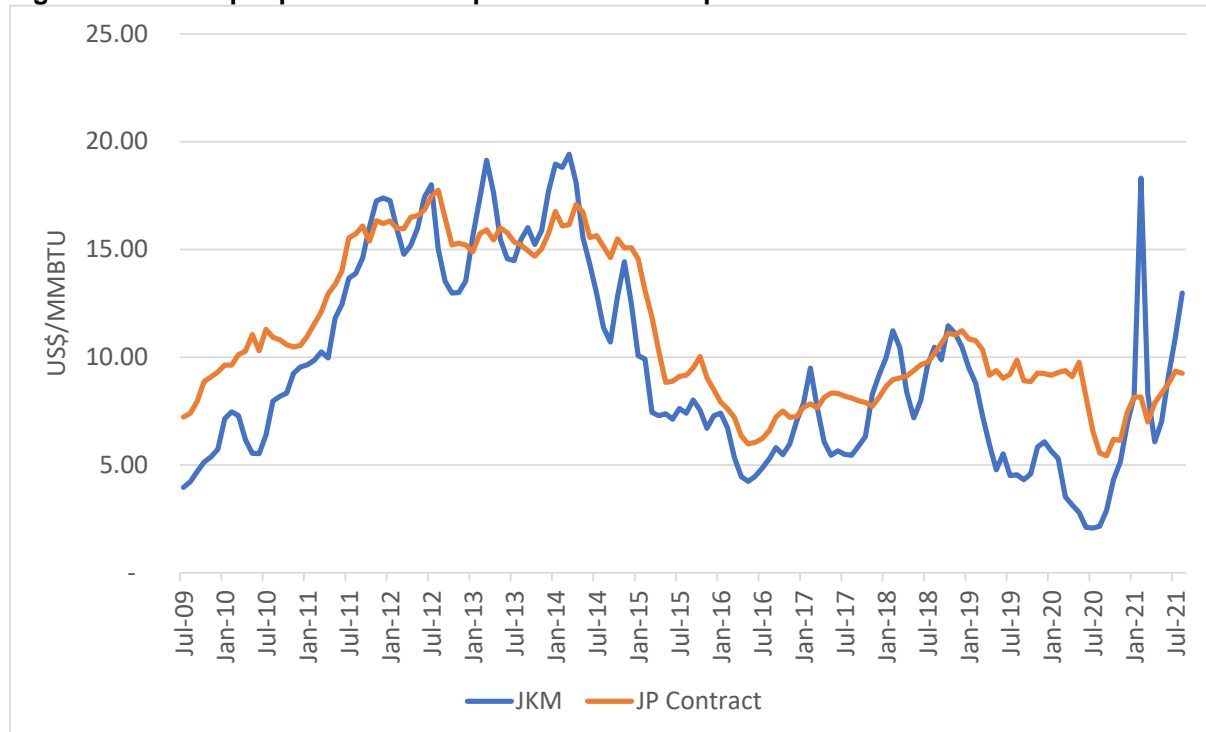
have also risen sharply, although by less than the TTF price, but the EU ETS price has also risen to provide a further boost to the carbon-adjusted coal price. Gas, therefore, has maintained its competitive position, providing some support to gas demand in Europe.

The forward curves suggest that the competitiveness of gas may well be maintained for most of 2022, if gas and coal prices decline in line with each other. If gas remains competitive with the adjusted coal price, then this would be supportive of gas demand in Europe going forward, at least while significant coal and lignite power remains in the energy mix.

1.3 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 seek changes 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 away from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation.

Figure 1.3: JKM spot price versus Japan LNG contract price



Source: Platts and Argus data, OIES analysis

In early 2019, there was a decisive break between the oil-linked contract price and the JKM spot price, as Figure 1.4 shows. Contract prices came down in early 2020 as oil prices had fallen a few months before. The prices began to converge towards the end of last year before JKM spot prices rallied in February. The summer rise in spot prices has seen JKM jump back above the contract price, at least briefly. At current oil prices, the level of oil-indexed contract prices is likely to be in the range of 9-10 USD/MMBtu over the next year. This is broadly similar to the forward JKM prices, at least through 2022. When spot prices were well below contract prices, there was discussion as to whether there would be a real challenge to oil-indexed contracts, if the trend persisted. However, with the prices converging again, this pressure has lessened, at least temporarily.

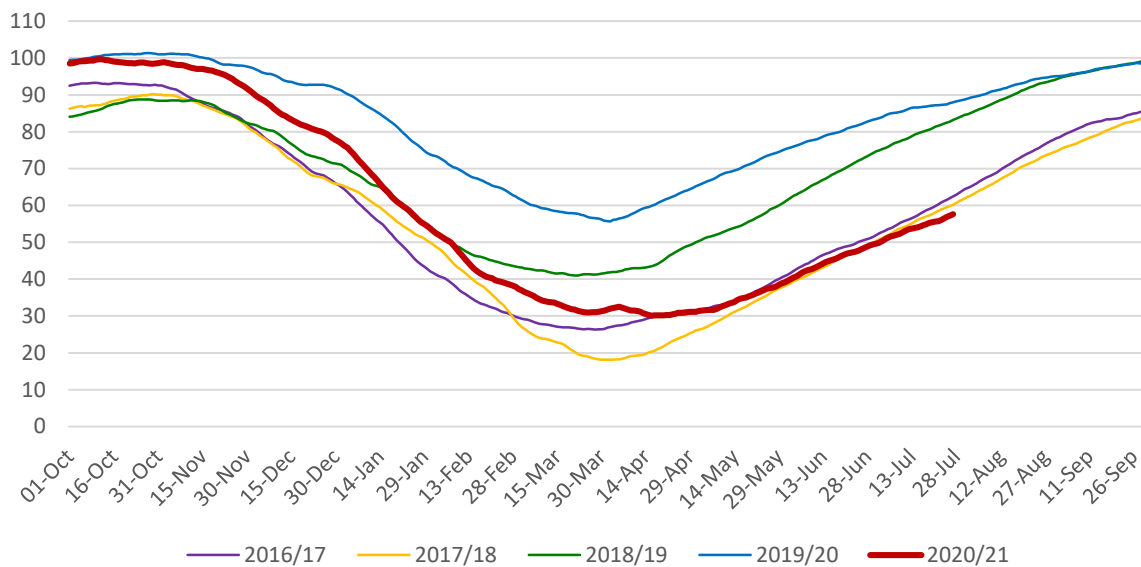
1.4 European gas storage

A ‘headline issue’ of recent months that has gone hand-in-hand with the gas price rally was the dramatic draw-down of European storage stocks in the winter of 2020/21, and the subsequent slow rate of storage injections that has accompanied the sustained high European price levels. As Figure 1.4 illustrates, the joint record-high stocks held at the start of winter (1 October 2020) were rapidly drawn down as Europe experienced cold weather, and LNG cargoes were pulled away to Asia.

In Q2 2021, the most notable development has been the slow pace of stock replenishment. A return to net withdrawals in the second half of April meant that stocks on 1 May were actually lower than on 1 April, thus delaying the start of the injection season by a month. Since then, injections have proceeded slowly. As a result, stocks held on 27 July 2021 (58 bcm) were slightly lower than on 27 July in 2017 and 2018 (62 bcm and 60 bcm, respectively), and significantly lower than stocks held on 27 July in 2019 (83 bcm) and 2020 (88 bcm). For stocks to reach even 80 bcm, by the end of the injection season in October 2021, net storage injections will need to accelerate in the coming months.

Starting the winter with significantly lower stocks than has been usual for the past several years will reduce the ‘buffer’ that Europe has to cope with market fluctuations during the coming winter, thereby increasing the likelihood of price surges should any significant shift in the supply-demand balance occur, for example due to weather or supply issues.

Figure 1.4: Stocks held in European storage (bcm)



Source: Data from Gas Infrastructure Europe Aggregated Gas Storage Inventory (AGSI+)

1.5 Gazprom’s Electronic Sales Platform: sales by delivery profile

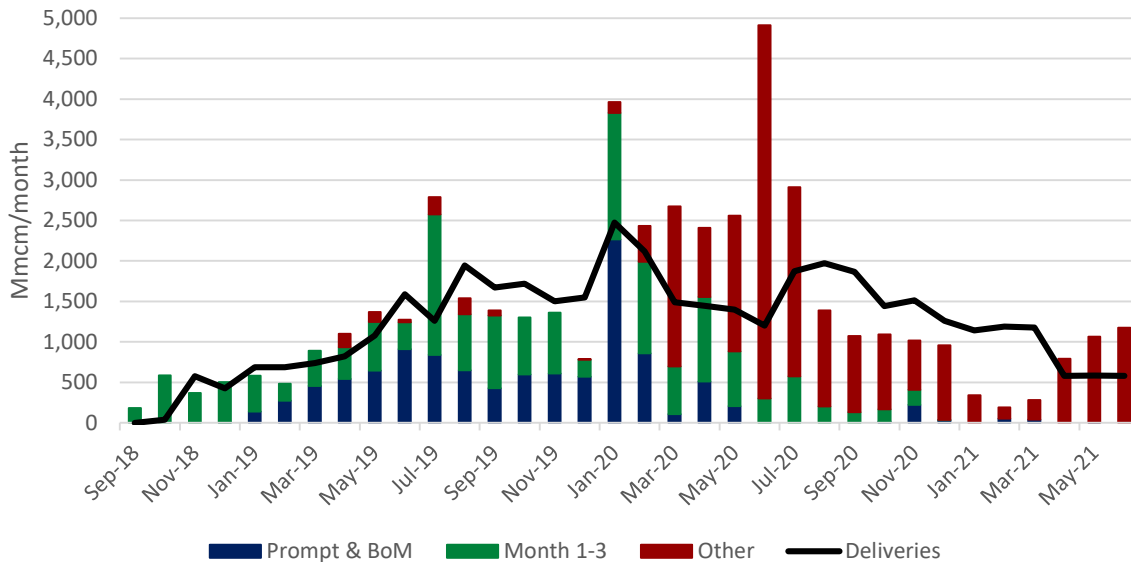
Despite the dramatic rise in European hub prices in Q2 2021, on the back of a tightening supply-demand balance, Gazprom’s sales via its Electronic Sales Platform (ESP) were once again limited in volume, and sales for near-term delivery were almost entirely absent.

In Q2 2021 as a whole, Gazprom sold 3,029 mmcm via the ESP, which was a significant rebound from the 813 mmcm that was sold via the ESP in Q1 2021. However, the sales in Q2 2021 were lower than those in Q2 2019 (3,741 mmcm) and Q2 2020 (9,881 mmcm).

Of the total sales in Q2 2021, just 3.4 mmcm was sold for prompt delivery (day-ahead and weekend for delivery to Bereg on the Ukraine-Hungary border). No volumes were sold for Balance of Month, Front-Month (i.e., Month-1), Month-2, or Month-3 delivery. Very little was sold for delivery by quarter: Just 29 mmcm for delivery in Q1 2022. Only a small volume was sold for delivery in winter 2021/22 (102 mmcm).

By contrast, substantial volumes were sold for delivery in Summer 2022 (309 mmcm), calendar year 2022 (2,305 mmcm), and even calendar year 2023 (281 mmcm).

Figure 1.5: ESP sales by delivery profile (mmcm/month)



Source: Gazprom Export, Argus Media, OIES

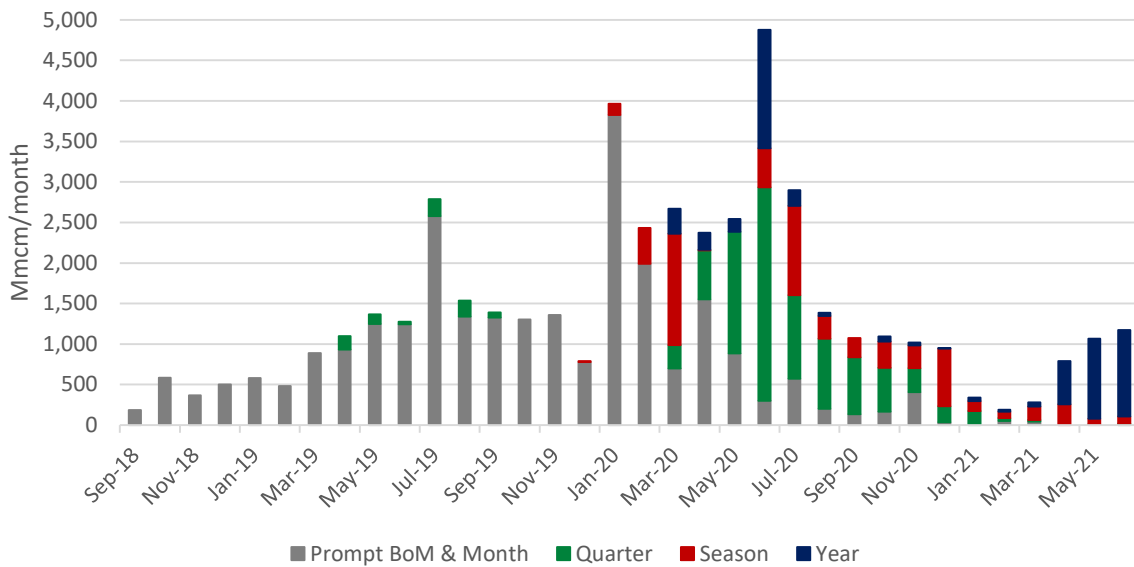
Another notable development in relation to the ESP was the decline in delivery volumes. These delivery volumes are calculated by taking the amount sold for delivery in a calendar year and dividing evenly across the twelve calendar months. To those is added the volume sold for delivery in a season (for example, Summer 2021), divided evenly across the six months of that season, and finally, volumes sold for delivery in a quarter are divided evenly across the three months of that quarter. To that total is added volumes sold for delivery in that specific month (either as Balance of Month, Front-Month, Month-2, or Month-3). Finally, all volumes sold for within-day, day-ahead, Saturday, Sunday, or Weekend delivery are allocated to the month in which they were delivered.

Overall, since January 2019, Gazprom has delivered at least 500 mmcm per month of gas sold via the ESP. Between May 2019 and March 2021, that figure was at least 1,000 mmcm, peaking at 2,474 mmcm in January 2020. Therefore, a notable development in Q2 2021 was the decline of deliveries of gas sold via the ESP to 581-584 mmcm per month in April, May, and June 2021 – The lowest levels since December 2018 (425 mmcm), when the ESP was still in its infancy.

Another significant development in Q2 2021 regarding ESP sales has been the growth in sales for delivery by calendar year as a percentage of total sales. In June 2020, sales for delivery by year (1,457 mmcm) accounted for 30 per cent of the total. However, this included the sale of 1,095 mmcm for delivery to Hungary following the expiry of the existing long-term gas supply contract, while Gazprom and its Hungarian counterparty negotiated a new long-term contract. If this sale to Hungary is excluded, then March 2020 saw the sale of gas for delivery by calendar year take the highest share of total sales (11 per cent).

By contrast, in April 2020 sales for delivery in the calendar years 2022 and 2023 accounted for 67 per cent of total sales, and this figure rose to 93 per cent in May and 91 per cent in June. In total, in Q2 2021, Gazprom sold 2,305 mmcm for delivery in 2022 at a flat rate of 6.3 mmcm/d and 281 mmcm for delivery in 2023 at a flat rate of 0.77 mmcm/d.

Figure 1.6: ESP sales by delivery profile (mmcm/month)



Source: Gazprom Export, Argus Media, OIES

Since March 2020, Gazprom has sold very little for prompt delivery and larger volumes for delivery further into the future. Using the calculation of delivery volumes by month explained earlier, the practical result in the coming months is that Gazprom will deliver approximately 598 mmcm per month (19 mmcm/d) to Europe of volumes sold via the ESP in July, August, and September, even if it does not make any sales for near-term delivery in those months. From October 2021 to December 2022, that figure is currently set to fall to between 252 and 333 mmcm per month (8-11 mmcm/d), although in reality that figure will rise as Gazprom makes additional sales for delivery in those months. The key point here is that Gazprom has already 'locked in' sales for delivery over the next 18 months, and is likely to add to those volumes with additional sales in the coming months.

2. The Tightening Global Gas Market

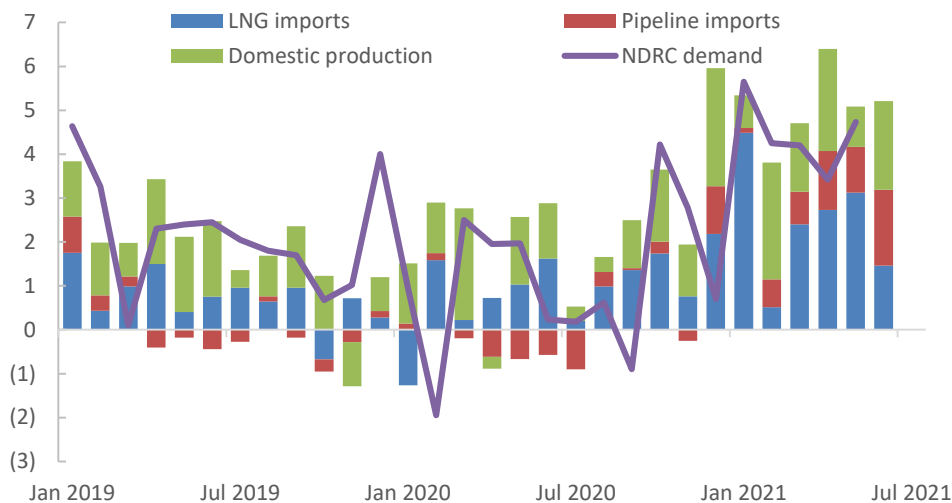
The rapid rise in global gas prices this year has reflected a tightening global gas market. The reasons for this have been widely discussed within the industry by participants and commentators. The cold winter prompted a significant rise in demand, especially in Northeast Asia, and strong demand has continued as the world economies recover from Covid-19. Supply has also been constrained by a number of issues surrounding LNG plants around the world as well as Nord Stream 2 not being completed. In this section we focus on demand in China and what is happening to Russian supply.

2.1 China's gas demand: From strength to strength

In the first half of 2021, China's implied gas demand (the sum of net imports and domestic production) reached 192 bcm, a strong 32 bcm increase compared to the same period in 2020 (figure 2.1). While part of the strength is due to the low base of H1 2020, when demand was impacted by the COVID-19 pandemic, economic growth and gas use in China recovered rapidly in 2020 and grew compared to 2019 level, contrary to many other countries where demand declined due to the pandemic. Indeed, even though economic activity and gas use were expected to grow rapidly this year, the strength has exceeded most estimates, including our own. Our forecast of around 40 bcm incremental demand in 2021 is likely to be easily surpassed. Indeed, the 2021 strength is due to the country's robust economic recovery, the power shortages that have ensued as well as new regas terminal expansions and storage additions.

Given the surge in gas use, even though domestic gas production rose strongly, LNG imports also increased dramatically, boosting global markets. China is now on track to displace Japan as the world's largest LNG importer this year. But with economic growth likely to moderate in 2022 and ongoing reforms in the power sector to encourage the use of renewables, gas demand growth may slow in 2022. That said, given the changes in China's gas market, and especially the focus on reliability in power supplies, gas consumption is likely to grow strongly again next year, possibly growing by some 30 bcm, compared to the OIES forecast of some 20 bcm. In 2019, China gas demand reached 300 bcm and by 2022 it could be close to 400 bcm.

Figure 2.1: China gas supply and demand, y/y change, bcm



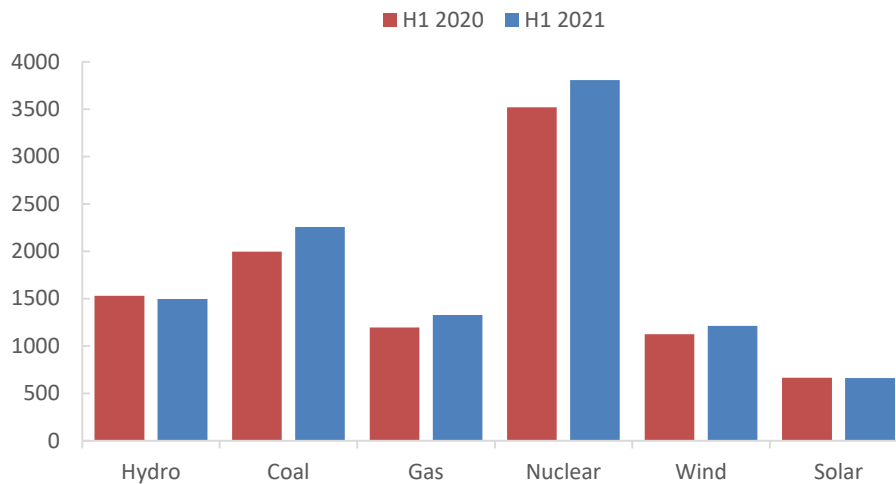
Source: China customs, NBS, NDRC

2.1.1 Powering up...

Fundamentals, namely strong demand, have been a key driver of China's gas use this year. In the winter, especially during the cold snaps that hit Asia in Q1 2021, space heating supported consumption. At the same time, the country's robust economic recovery, which has been led by industrial activity, also generated a large uptick in gas demand given that industrial and commercial users are the largest gas consumers in China. But it is increasingly the power sector that is driving demand for gas and LNG. The uptick in power demand for gas in 2021 was due to a combination of strong economic momentum and supply constraints. Indeed, in the first half of 2021, electricity consumption grew by 16 per cent, with industrial demand rising by 17 per cent y/y and accounting for two-thirds of total power use. Even though gas accounts for a small share of power generation (just over 3 per cent in 2020), in H1 2021, gas-fired power generation increased by 13 per cent y/y, compared to coal and hydro, which grew by 2.5 per cent and 4.6 per cent respectively.

Gas in power has been particularly significant in Southern China, where it plays a critical role in peak-shaving supply. This year in particular, the strength of economic activity in China's manufacturing and export hubs in Southern China combined with tight coal supplies—due to a combination of safety inspections at China's domestic coal mines and the ban on imported Australian coal—tightened regional power markets considerably. And with summer temperatures higher than normal, demand been stronger than expected. At the same time, solar power output fell short of expectations and low rainfall in Southwest China—a key source of hydropower supply for China's large manufacturing and exporting hub of Guangdong—has further constrained supplies. To keep up with demand, power plants have purchased more gas and are running gas-fired units for longer, with average utilisation hours at gas fired-power plants up by 11 per cent from H1 2020 levels, on par with the increase in utilisation hours in coal-fired power plants, but higher than the 8 per cent increase for both nuclear and wind, according to the China Electricity Council.

Figure 2.2: China power generation, average utilisation hours



Source: China Electricity Council

2.1.2 Supply security 2.0

In response to the current tightness and expected increases in power demand, the Chinese government in late July asked domestic gas and coal suppliers to make more thermal fuels available to the power sector, by raising domestic production and to the extent possible, bringing forward gas field start-up dates. But with few new fields expected to start up after CNOOC reportedly commissioned its offshore Lingshui 17-2 gas field in late June, China will need more imports. Already LNG buyers that supply downstream demand in Southern China have been seeking spot cargoes for August delivery. Indeed, policy documents issued in July are reiterating the need to ensure supplies over the summer months, calling on gas producers, importers and shippers to ‘jointly ensure reasonable natural gas supply capacity’ and ‘rationally arrange infrastructure maintenance’ for peak summer demand.

The government’s call for importers and pipeline companies to ‘jointly’ ensure supplies is another reminder and warning that the winter shortages should not repeat themselves. Indeed, even before this latest power crunch, China’s state-owned majors had started stocking up on LNG in order to avoid a repeat of the 2020-2021 winter shortages. Even though the main importers blamed PipeChina, China’s newly created midstream company, for the supply shortage during the winter cold snap, they were still reportedly reprimanded by the government for not being well enough prepared and have sought to secure stock up earlier this year. What is more, following the creation of PipeChina, the state-owned majors have been adapting their sales strategies: since they had to transfer their inter-provincial oil and gas pipeline assets, storage facilities and import terminals to PipeChina, they have been looking to supply gas locally to reduce reliance on long-distance pipeline transport. This has also meant that CNPC, for instance, booked less gas through the West-East pipeline to coastal provinces, opting to sell the gas locally. CNOOC, for instance, continues to focus on marketing its imported LNG in eastern and southern coastal regions and fend off newcomers who will now also be able to import gas through PipeChina infrastructure.

For now, uncertainties over import costs through PipeChina have cooled private buyer’s enthusiasm. In January 2021, PipeChina opened up delivery slots into its regas terminals, but then suggested that each new importer would have to purchase one legacy-priced cargo (from the state-owned majors’ long-term contracts) in order to win a slot for a spot import shipment.

Over time, the import and price arrangements will be ironed out, with some new importers such as Guangzhou Gas, ENN Group and Beijing Gas Group already securing supply deals—using both oil-indexation and Asian spot indexation—but these changes should lead to better resource allocation within China and increase supply availability.

In the near term, though, as the government continues to urge importers to stock up, new regas expansions and storage starts will support gas flows. In late June, ENN brought online a 2 Mtpa expansion at its Zhoushan LNG terminal in Southern China—bringing its nameplate capacity to 5 Mtpa. The company also added 320,000 m³ of storage capacity which should begin commercial operations in Q4 2021, ahead of the winter heating season. According to ENN, it has also doubled the capacity of regasification and truck-loading facilities as part of the expansion, allowing the terminal to operate at a maximum turnaround capacity of 8 Mtpa. Sinopec is also expanding its 6 Mtpa Qingdao and Tianjin terminals, adding 1 Mtpa to the former and 4.8 Mtpa to the latter. Sinopec is also adding 1.1 million m³ of storage and another LNG berth with 266,000 m³ capacity for the Tianjin terminal, as well as 320,000 m³ of storage at the Qingdao expansion. The Qingdao expansion is scheduled to start this summer while Tianjin should come on line in November, ahead of the winter heating season.

2.1.3 A pivot to pipelines

Utilisation rates at Tianjin could be bolstered by the construction of a new domestic pipeline which will supply the wider Beijing-Tianjin-Hebei area. PipeChina, started construction of the first 7 bcma phase of the new pipeline in April. While the completion date is unclear, the pipeline should connect the northern regas terminals to demand centres and provide additional supply routes for the Power of Siberia pipeline gas into the domestic midstream network and gas storage facilities in north China. Flows from Russia through the Power of Siberia pipeline will continue to increase as this is also currently China's lowest cost source of supply. In addition to higher flows from Russia, imports from Turkmenistan also increased this year and are set to rise marginally next year too. For now, with oil-indexed LNG as well as spot LNG prices rising, buyers have been opting for lower-cost pipeline gas.

Pipeline imports into China are oil linked, and while they tend to have a lower slope than LNG contracts, there is an estimated 9-12 month lag with oil prices (as well as a higher fixed element to the pricing formula). Oil-linked LNG contracts, however, tend to have a 2-3 month lag but an average slope of 12-13 per cent. This means that pipeline imports should be competitive with oil-indexed LNG (as well as spot LNG at its current values) throughout 2021. But despite their lower cost, incremental pipeline gas supplies, especially into Southern China are limited and since power generators still need to ensure electricity supply, LNG flows into China will continue, even at a higher cost.

2.1.4 2022: Still going strong

China's gas demand in 2021 is driven by temporal factors, namely, the robust economic activity and the related power shortages, as well as storage and regas terminal starts. Will these trends continue in 2022? The strength in economic activity is widely expected to soften, suggesting slower demand growth from industrial and commercial users. But rising power demand and the need for gas peakers, especially along China's coastal provinces, is set to continue. Meanwhile, a new pipeline tariff mechanism alongside further liberalisation of China's midstream will support new supplies.

2.2 Russia Supply and Gazprom Strategy

With European hub prices climbing to record levels for this time of year, a question that has been increasingly asked by analysts is whether Gazprom – as the single largest supplier to the European market – is pursuing a sales strategy that aims at leveraging its market power to maintain such prices. Specifically, is Gazprom 'holding back' volumes to ensure the market remains tight, by not booking (and utilising) additional transit capacity via Ukraine?

2.2.1 Gazprom's routes to Europe

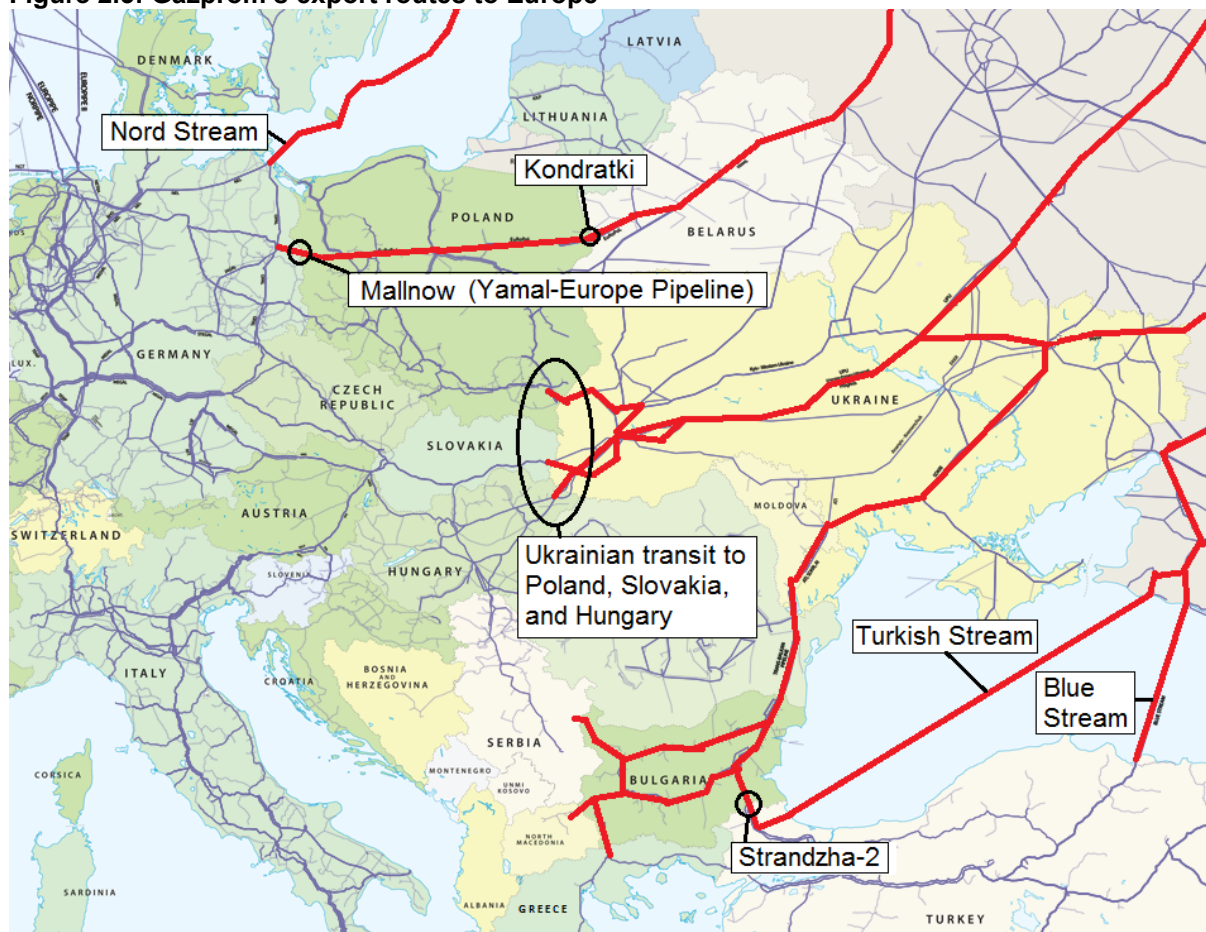
The first point to address is the range of routes by which Gazprom delivers gas supplies to Europe.² The single largest route is the Nord Stream pipeline, direct from Russia to Germany. With a capacity of

² In this case, 'Europe' excludes Turkey due to a lack of daily gas flow data

164 mmcm/d, Gazprom consistently operates this pipeline at full capacity, aside from the 10-day maintenance periods every July.

A second major route to North-Western Europe is the Yamal-Europe pipeline from Russia to Germany via Belarus and Poland, which has a capacity of 98 mmcm/d. Gazprom owns that pipeline in Belarus through its wholly-owned subsidiary, Gazprom Transgaz Belarus. On Polish territory, the Yamal-Europe pipeline is owned by EuRoPol GAZ, which is a joint venture of Gazprom (48 per cent), PGNiG (48 per cent), and Gas-Trading S.A. (4 per cent). PGNiG acquired a controlling interest in Gas-Trading S.A. in 2015, which it still holds.³

Figure 2.3: Gazprom’s export routes to Europe

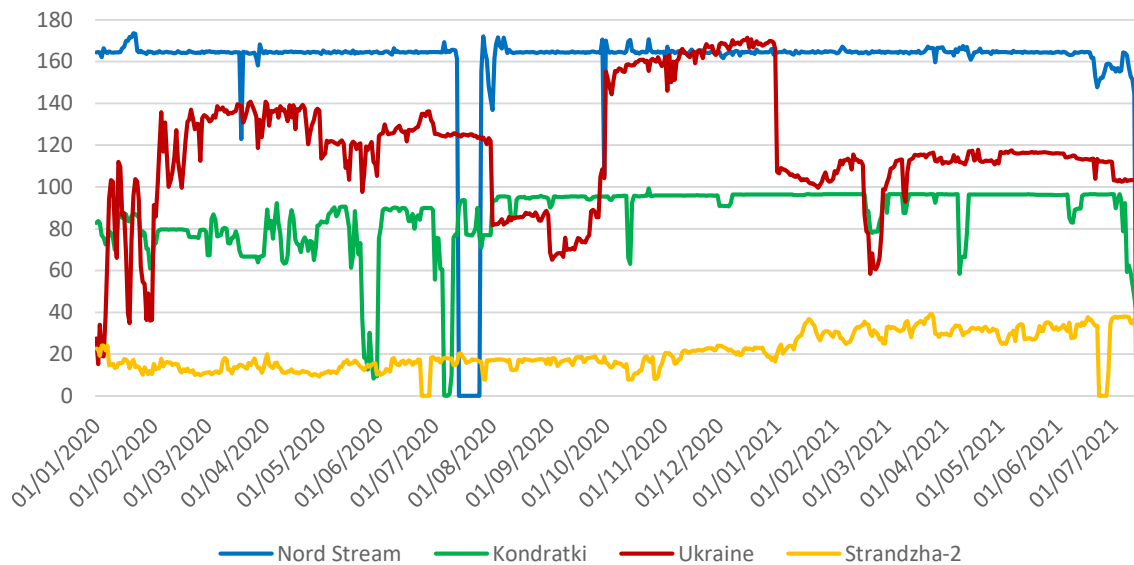


Source: Original map from ENTSOG Transparency Platform, annotated by the author

As the graph below illustrates, the Nord Stream (blue) and Yamal-Europe (green) pipelines have both been operating at full capacity since at least early August 2020. Gazprom’s long-term transit contract for deliveries via Poland using the Yamal-Europe pipeline expired in May 2020. Since then, Gazprom has booked capacity via Poland through auctions held by the Polish TSO, Gaz-System. In doing so, Gazprom has booked the majority of its required capacity on an annual basis, leaving a small amount of flexibility through monthly capacity bookings. Should Gazprom face declining call on its gas in North-Western Europe, its likely first response will be to reduce its monthly capacity bookings via Poland.

³ PGNiG, 2021. *Directors Report on The Operations of PGNiG SA and the PGNiG Group For 2020*. https://en.pgnig.pl/documents/1910852/3137822/Directors%27+Report+on+the+operations+of+PGNiG+SA+and+PGNiG+Group+for+2020_www+version.pdf/06e07a0e-c6b9-42eb-a075-8381e4f00d71 (see page 116)

Figure 2.4: Total Russian gas flows to Europe by route (mmcm/d)



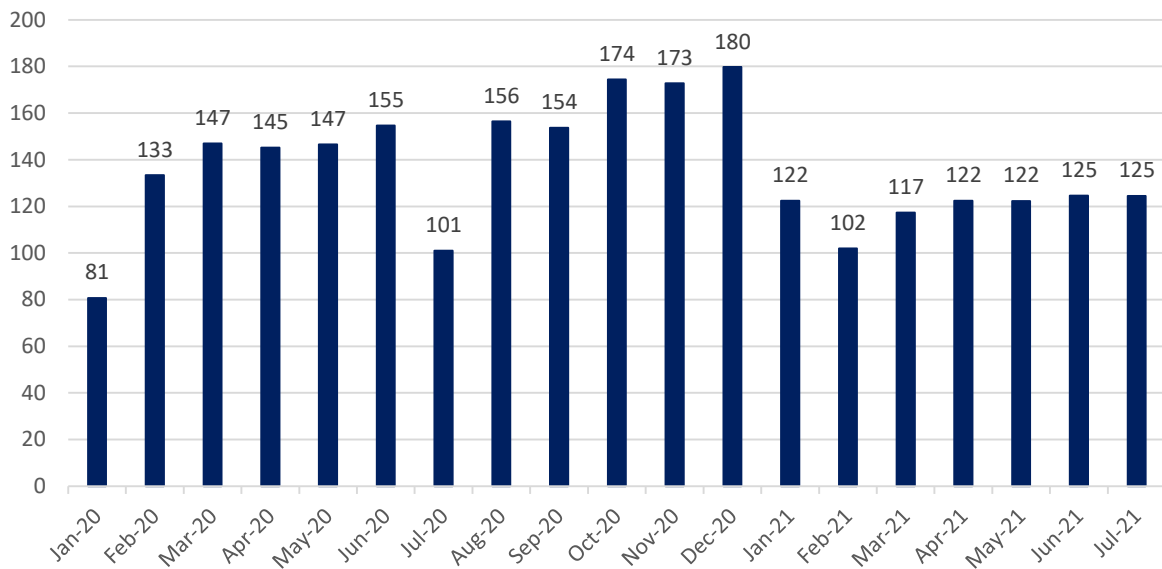
Source: Data from ENTSOG Transparency Platform

In South-Eastern Europe, the Strandzha-2 cross-border interconnection is located on the Turkey-Bulgaria border. Here, gas delivered to Turkey via Turkish Stream is transited on to Bulgaria, where it is either consumed or delivered onward to Greece, North Macedonia, or Serbia. The interconnection between Bulgaria and Serbia was launched on 1 January 2021, and this explains the uptick in flows at that time. These markets in South-Eastern Europe are not connected to the broader European market, and so Gazprom could not increase flows via Strandzha-2 as a means of providing larger volumes to its counterparties in Central or North-Western Europe. From 1 October 2021, an interconnection between Serbia and Hungary will enable Hungary to receive volumes via Turkish Stream, which will increase flows via Strandzha-2 and could thus enable flows via Turkish Stream to impact the Central European market for the first time. This is possible because of Hungary's cross-border interconnections with Austria and Slovakia.

The route with the greatest swing is Ukraine (red in the graph above) where, Gazprom's transit capacity is underpinned by a long-term contract that is valid from 1 January 2020 to 31 December 2024. For 2020, Gazprom pre-booked (and pre-paid) for 178.1 mmcm/d (some 65 bcm annualised) of entry capacity on the Russia-Ukraine border (at Sudzha and Sokhranovka), and an equal amount of exit capacity to be distributed (according to Gazprom's nominations) across interconnection points on Ukraine's western border, with Poland, Slovakia, Hungary, Moldova, and Romania. From 1 January 2021, that pre-booked capacity fell to 109.6 mmcm/d (some 40 bcm annualised).

As the Figure 2.5 illustrates, data from the ENTSOG Transparency Platform shows that Gazprom's monthly average gas flows via Ukraine (the combined entry flows from Russia to Ukraine at Sudzha and Sokhranovka) reached a high of 180 mmcm/d in December 2020, with Gazprom booking a small amount of additional capacity to facilitate those flows. In 2021 to date, Gazprom has also booked additional capacity, but its monthly average physical flows via Ukraine have yet to surpass 125 mmcm/d. Those ENTSOG figures are matched by the volumes reported by GTSOU. That GTSOU data states that physical flows have been consistently 124-125 mmcm/d since 16 March 2021, which is precisely in line with the capacity available to Gazprom following its bookings of additional capacity, beyond its baseline of 109.6 mmcm/d.

Figure 2.5: Monthly average Russian gas flows into Ukraine (mmcm/d)



Source: Data from ENTSOG Transparency Platform. Note: These flows are entry flows from Russia to Ukraine as measured at the Sudzha and Sokhranovka border points.

2.2.2 Gazprom's capacity bookings via Ukraine

Given that Gazprom is currently flowing gas to North-Western Europe (via Nord Stream and Yamal-Europe) at full capacity, and flows via Stranzha-2 are limited by counterparty demand and a lack of onward connections to the broader European market, the question raised by various analysts in recent months is why Gazprom has not booked substantial additional capacity via Ukraine. The physical flows in Q4 2020 - when Gazprom's flows to Europe via Ukraine averaged 175.6 mmcm/d - show that the Ukrainian system is certainly capable of delivering such volumes, just as Gazprom is capable of producing them and bringing them from Russia's gas-producing regions to the Ukrainian border.

In anticipation of its pre-booked capacity via Ukraine declining sharply in January 2021, Gazprom did indeed book substantial extra capacity via Ukraine: In an auction held on 21 December 2020, the Ukrainian TSO, GTSOU, offered 41.6 mmcm/d of firm monthly capacity for entry at Sudzha on the Russia-Ukraine border for January 2021, of which Gazprom booked 41.2 mmcm/d. However, total flows from Russia into Ukraine that month averaged only 122 mmcm/d.

For capacity in every month since February, GTSOU has offered 15 mmcm/d of firm monthly capacity, and Gazprom has booked either 14.2 mmcm/d (for February, March, and April) or 15.0 mmcm/d (for May, June, July, and August). For May, June, July, and August, GTSOU also offered 63.7 mmcm/d of interruptible monthly capacity, which Gazprom declined to book.

At auctions in November 2020, February 2021, and May 2021, GTSOU offered 15 mmcm/d of firm quarterly capacity, which Gazprom declined to book. Then, on 5 July, GTSOU offered 15 mmcm/d of firm annual capacity for the next four gas years, starting 1 October 2021, and Gazprom again declined to book that capacity.

Finally, on 19 July, GTSOU offered 78.3 mmcm/d of firm entry capacity at Sudzha and 33.84 mmcm/d of firm entry capacity at Sokhranovka (a total of 112 mmcm/d), to be booked on an annual (gas year) basis, starting 1 October 2025 and running all the way to gas year 2035/36. In doing so, GTSOU effectively offered Gazprom the opportunity to extend its current long-term transit contract for another 10 years beyond the expiry of the existing contract. However, Gazprom declined to book any of that

offered capacity.⁴ The overall result is that Gazprom's transit capacity via Ukraine has been stable at 124-125 mmcm/d (some 45 bcm on an annualised basis) since 1 February 2021.

Two key conclusions can be drawn from these auction results: Firstly, Gazprom is only interested in booking monthly firm capacity. Secondly, GTSOU is limiting its firm monthly offerings, possibly in the hope that Gazprom will book quarterly or annual capacity. The result is that Gazprom has refused to be tempted into booking capacity for longer periods, and now faces accusations of limiting its gas flows to Europe via Ukraine, on the grounds that it could book more capacity and therefore flow larger volumes.

In terms of the annual capacity on offer, Gazprom seems to be hoping that Nord Stream 2 will be brought into operation before it needs to book additional annual capacity. It is likely that Gazprom does not wish to book interruptible capacity because it will take on firm commitments to supply that gas to its European counterparties, and thus be liable for any interruptions. Finally, given the sustained demand for Russian gas in Europe in 2021 so far – and Gazprom's own need to replenish its downstream storage stocks – Gazprom could certainly have booked quarterly capacity when it was offered in February or May at a volume of 15 mmcm/d, and then been more flexible about how much it booked on a monthly basis. It is not clear why Gazprom chose not to follow this path.

The fact that Gazprom did not book additional capacity via Ukraine – and then utilise that capacity by offering additional volumes either on its Electronic Sales Platform or on hubs in Central Europe and Italy – is likely due to its desire to maximise revenues across its entire portfolio. Here it is worth noting the size of Gazprom's long-term contract portfolio and its pricing structures. Firstly, Gazprom reports sales to the EU+UK of 176-177 bcm in 2018 and 2019, falling to 160 bcm in 2020.⁵ Most of these volumes are supplied under long-term contracts. Secondly, at the 2021 Gazprom Investor Day, the Director of Gazprom Export, Elena Burmistrova, reported that 56 per cent of Gazprom's export sales were linked to day-ahead or front-month hub prices, a further 31 per cent were linked to forward prices (quarter, season, and year), and just 13 per cent linked to the price of oil.⁶

Therefore, Gazprom has a substantial sales portfolio by volume that is heavily linked to prompt and forward prices in European hubs. In aiming to maximise its sales revenues, Gazprom's sales strategy is likely to be based on meeting all of its counterparty nominations under long-term contracts and then additionally supplying just enough to the spot market (either via the ESP or through its trading subsidiaries active on European hubs) to maximise its benefit from the current price levels, but not so much as to reduce those prices by a meaningful amount.

Gazprom has been under pressure for much of the past decade to include greater hub-price components in its long-term contracts. Indeed, this was an implicit part of its settlement with the European Commission following its anti-monopoly investigation into Gazprom.⁷ In 2020, Gazprom suffered from exceptionally low prices, especially during the summer. However, just 12 months later, it is now reaping the benefits of hub-indexation. Moreover, it has clearly realised that the current situation is to its advantage, and may well be pursuing a sales strategy that maximises its benefits from the current tight market. Having its portfolio exposed to hub prices is certainly a disincentive for Gazprom to 'flood the market' with substantial extra volumes via Ukraine, thus bringing those hub prices down. Furthermore, Gazprom's LTC counterparties might be paying high prices at present, but they are doing so because of prevailing gas market conditions. This is in stark contrast to the situation a decade ago, when those counterparties faced oil-indexed long-term contract prices that were significantly above the prevailing hub prices, and responded by launching arbitration cases.

4 The results of all these auctions can be found at the following: Regional Booking Platform, 2021. Capacity auction results. <https://ipnew.rbp.eu/rbp.eu/#capacityauctions>

5 Reuters, 2021. ТАБЛИЦА-Экспорт Газпрома по странам в 2020г (TABLE-Gazprom's exports by country in 2020). Reuters, 15 February. <https://www.reuters.com/article/-2020-idRUL8N2KL3N1>

6 Gazprom, 2021. Investor Day 2021 presentation. <https://www.gazprom.com/f/posts/23/378358/invest-day-2021-presentation.pdf> (see page 34)

7 The settlement did not argue against oil-indexation per se, but Gazprom undertook commitments to offer price revisions if its contractual prices diverged substantially from prices on European hubs

To conclude, the stark difference in market conditions between mid-2020 and mid-2021 highlights something fundamental about Gazprom's place on the European gas market. When that market is supply-long and awash with LNG, Gazprom cannot realistically pull sufficient volumes off the market to tighten the supply-demand balance and raise prices, OPEC-style. This is partly due to its long-term contract commitments, and partly because it would likely lose substantial spot sales volumes without benefitting from a meaningful price increase – It would simply cede market share to competing suppliers. By contrast, in a tight market, Gazprom has the spare productive capacity and – via Ukraine, at least – the export capacity to offer greater volumes to the European market on a spot basis. However, it is well within its rights not to do so, as long as it continues to meet all of its contractual commitments to its counterparties. In a supply long market (2019 and 2020) Gazprom is effectively a price-taker, but in a very tight market, Gazprom has some degree of pricing power, to the extent that it could soften prices by putting more supply on the market.

Compared to the situation when the majority of Gazprom's volumes to Europe were oil-indexed, the incentive to increase spot volumes is significantly diminished. Oil indexation effectively guaranteed a certain level of revenue for Gazprom, allowing it to place volumes on the spot market and reduce spot prices, with little impact on its overall revenues. With the vast majority of Gazprom's sales now hub indexed, any attempt to sell significant volumes on the spot market could reduce prices for almost all Gazprom's volumes and materially damage revenues. The European buyers and the European Commission pushed for more hub indexation as part of contract renegotiations – sometimes you need to be careful what you wish for!

3. Conclusions

At the beginning of Q2 2021, we discussed a winter of price surges, which reflected weather conditions that had been colder than the past several years, and led to LNG cargoes being diverted from Europe to Asia, with Europe effectively balancing the market by drawing heavily on storage stocks. At the time, we wrote in the previous edition of the *Gas Quarterly* that the high forward gas prices in Europe and Asia may have incorporated a 'fear factor' as the market recovered from a tight winter.

The market remained tight after the end of winter. Although prices in Europe and Asia fell back after the worst of the 'winter surge' in January, prices across all three global benchmarks rose substantially in Q2 2021. By the end of the quarter, those benchmarks reached 14-15 USD/MMBtu in Asia, above 12 USD/MMBtu in Europe, and above 3 USD/MMBtu on the Henry Hub in the United States. At the same time, Europe experienced rising prices for both coal and carbon credits. So, the general picture was one of a much tighter-than-usual market in the first half of summer.

This tighter market and its related price levels have impacted storage dynamics in Europe. Not only were storage stocks drawn down in winter to levels not seen for several years, but in Q2 21 the net injections were either absent on a whole-month (in April) or slower than in recent years (in May and June). From late June onwards, stocks levels were lower than on the same day in any of the previous four years. While the current high prices may be dissuading injections, the prospect of lower year-on-year storage stocks going into the coming winter is supporting a bullish pricing outlook.

Part of the reason for a tighter market in Europe is that Russian supply volumes have not yet returned to the pre-COVID levels. Gazprom's prompt sales via its Electronic Sales Platform remained virtually zero in Q2, with most sales for delivery in 2022. Gazprom is currently flowing as much as possible to North-Western Europe and meeting its counterparty nominations in South-Eastern Europe, but physical transit via Ukraine to Central Europe and Italy in Q2 2021 remained substantially down year-on-year, because of the lower transit capacity bookings on the Ukraine route. Given Russia's role as the largest external supplier to the European market, this has supported the high prices.

Another key factor behind the tightening market has been the rapid rise in China's gas demand – much more than expected – which has largely been reflected in rising LNG imports. As a result, China could well overtake Japan as the largest LNG importer this year. This growth in demand has been driven by temporal factors, namely, the robust economic activity and the related power shortages, as well as

storage and regas terminal starts. In the first half of 2021, gas demand was already some 32 bcm higher than the same period in 2020 – around 80 percent of the total increase we had anticipated for this year.

To conclude, the overall picture in Q2 2021 was that of a tight market at a global level for LNG (as evidenced by our ‘LNG tightness’ analysis) and in Europe (accompanied by higher coal and carbon prices). Looking forward to both Q3 2021 and the coming winter of 2021/22, it is possible that this market tightness will persist, resulting in an extended period of relatively high prices. This certainly seems to be the market sentiment, given the forward prices in Europe (TTF) and Asia (Argus North-East Asia) through to Spring 2022. Throughout Q3 2021, the signposts we will continue to look for are the rates of storage injection in Europe, the start-up of Nord Stream 2, and developments at LNG export terminals that could bring back supply that is temporarily offline, plus new projects coming onstream. All of these factors will influence the supply available to the global market, and by extension, the market situation at the start of winter. In the near term, Q3 2021 seems likely to experience a continuation of the trends seen in Q2 2021. Looking further ahead, if the global market enters the winter period with lower-than-usual storage stocks in Europe, Nord Stream 2 not coming on during the winter, substantial LNG export capacity possibly still offline, and demand continuing to rebound, the market could effectively ‘walk a tightrope’ through the winter: a mild winter could pass without incident, but either a weather-related demand surge or a supply-side disruption could see prices once again surging, as they did in January 2020.