



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

Introduction

The second quarter of 2022 has been a dramatic one for the European gas market. On the supply-side, the record volume of European LNG imports seen in Q1-2022 was slightly exceeded, meaning that LNG sendout in Q2 was around 10 Bcm (39 per cent) higher year-on-year. These increased LNG supplies were necessary to offset the 17 Bcm (45 per cent) year-on-year decline in pipeline imports from Russia. Elsewhere, the combined impact of higher production and higher imports from Norway and Azerbaijan more than offset lower pipeline supplies from North Africa, resulting in a net year-on-year gain of 5.2 Bcm from those sources combined. Taken together, the net result was a year-on-year decline in total gross supply (excluding storage stock changes) of around 1.8 Bcm (1.5 per cent), from 119 Bcm in Q2-2021 to 117 Bcm in Q2-2022.

However, the pricing and geopolitical environment is substantially different to that of Q2-2021. Prices are currently at exceptionally high levels, while record Spring storage injections took substantial volumes off the market. Uncertainties over continued Russian pipeline supply and a vastly greater exposure to the global LNG market – which is itself, already tight and exhibiting high prices – are generating European concerns over market balancing in the coming winter

In this Quarterly Review, we assess the impact of the present market situation on LNG margins, as a motivator for LNG project FIDs, and inter-fuel dynamics in Europe, before taking a deeper dive into the supply-demand balance on the European market in recent months and the key factors in that balance. There are two special sections. Firstly, 'In the Bleak Midwinter' considers the EU proposal to reduce gas consumption during the coming winter and the impact of a complete curtailment of Russian flows to the EU. Secondly, the outlook in China. The extent to which Chinese LNG demand rises or falls has a significant impact on the availability of LNG for Europe, and we examine the economic context behind China's current LNG demand dynamics.

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

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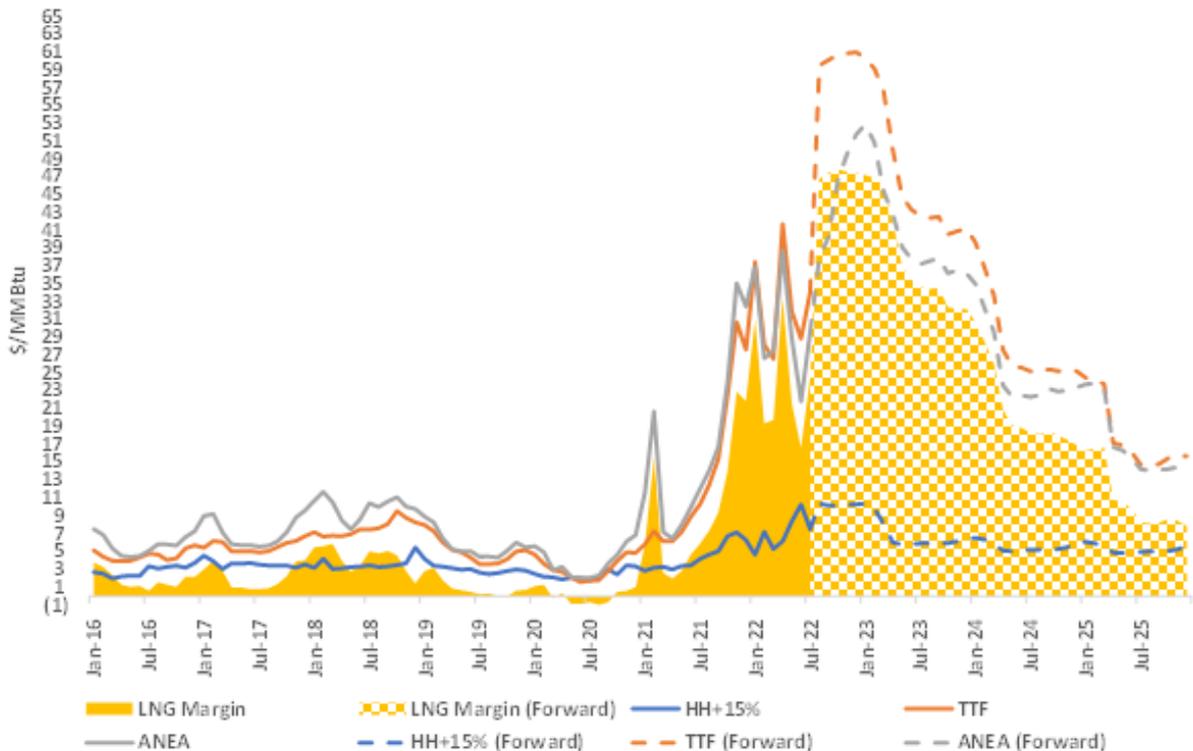
1. Price analysis

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

1.1 LNG tightness

As usual, we first 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. Figure 1.1 is based on data from Argus Media and shows the prices for regional benchmarks: TTF in the Netherlands, the Argus North-East Asia (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/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 26 July 2022

The negative margins in 2020, as a result of the COVID-19 pandemic, seem a distant memory now. Between 150 and 200 cargoes were shut in, which started to impact the market during the summer months. The picture changed dramatically as 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. 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.

Prices fell back quickly after the Asian spike, but the continuing tightness of the global supply-demand balance led to firm prices throughout the summer of 2021. In August, however, prices started to rise dramatically in both Europe and Asia, seeming to incorporate a large ‘fear’ premium, pricing in another cold winter. There were also reports of some short covering by LNG traders in Asia supporting the price,

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and some traders having large short open positions on TTF which resulted in significant margin calls.¹ These short positions needed to be covered by buying on the physical or futures markets, providing short term price support.

In December 2021, the price volatility increased with prices moving as much as 10 per cent up and down in a day on little more than good or bad news and windy or non-windy days in Europe. Prices were further supported as flows were significantly reduced along the Yamal Europe pipeline from Russia. As we entered 2022, Russian flows declined further, for reasons discussed in section 2.1. The lower Russian flows were broadly offset by much higher LNG flows into Europe, which is discussed in more detail in section 2.2.

Towards the end of February, the Russian invasion of Ukraine occurred. This sent prices in Europe spiralling higher and dragging up Asian spot prices as well. Henry Hub prices in the US also rose with the rising demand for LNG exports straining US supply. In the five months since the Russian invasion, prices have been on a rollercoaster ride. TTF prices settled down somewhat after the first few weeks following the invasion, but in late June and July, began to surge again, as Gazprom reduced flows significantly on Nord Stream – discussed further below. The forward curve for TTF is now touching \$60 per MMBtu for this coming winter. There was a time early last year when the \$/MMBtu axis on the chart barely reached \$20 – it has now expanded to over \$60. Truly, we are living in interesting times.

The current margins for LNG coming to Europe this winter are almost at \$50 and even as the forward curve declines, the margins are still very healthy out to 2025, providing strong incentives for new FIDs. However, it is not just the margin which will be needed for FIDs to be forthcoming. Even if the economics look good, most new LNG developments still require the backing of long-term contracts. This now appears to be happening with multiple announcements of new long-term contracts, especially with US developers. Many of these have been to the Asian markets, including China, but we have also seen a few for European buyers.

As is widely reported, the LNG FIDs taken a year or two ago – pre-COVID – will result in an enormous surge in LNG export capacity from the mid-2020s onwards. By 2028, global LNG export capacity is likely to be 50 per cent higher than in 2021. With more long-term contracts being entered into and continuing high margins, the prospects for more FIDs in the next 18 months or so look very promising, especially from the US.

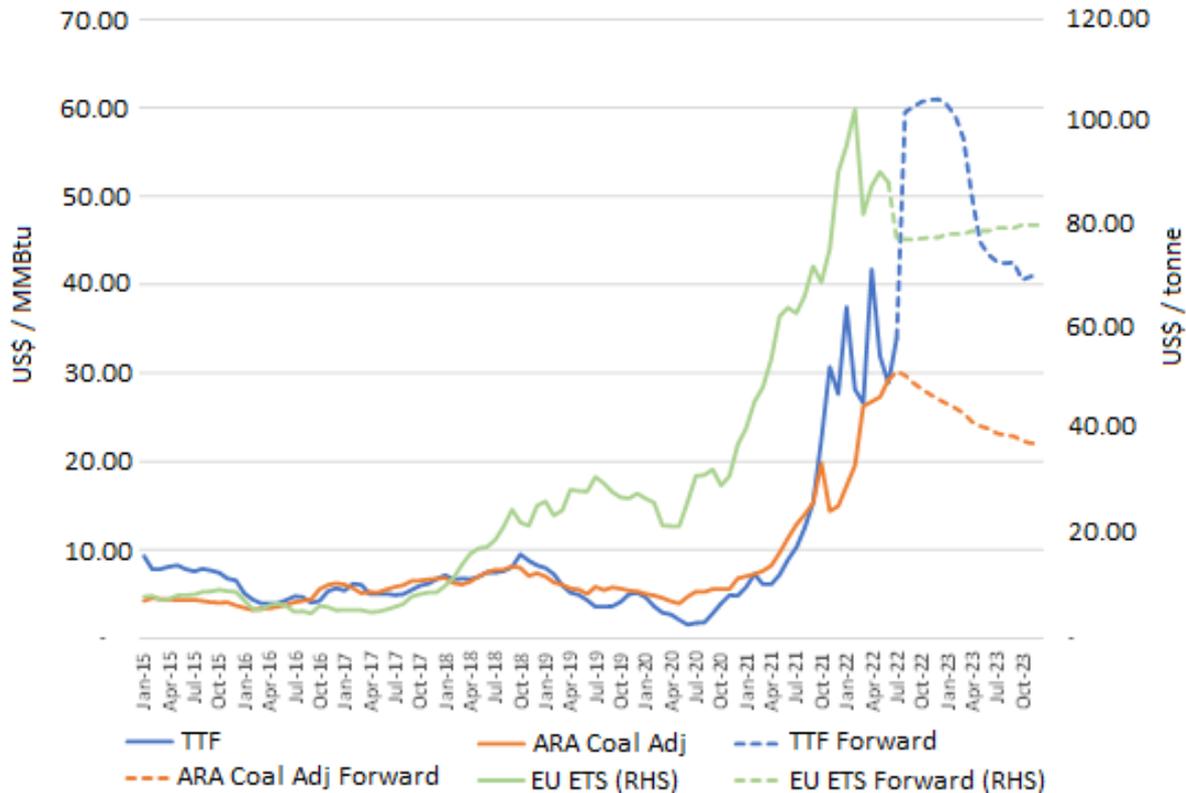
One final word on the forward curve. As the chart shows, by 2024 the TTF and ANEA forward curves are in the mid-\$20 and by 2025 in the mid-teens. What is changing between now and 2025 that is causing the market to ‘believe’ that prices will decline by such large amounts? The big surge in LNG supply is really post-2025. For prices to decline, as portrayed in the chart, either pipeline supply from Russia to Europe needs to rebound strongly, from the current very low flow rates discussed below, or there needs to be a sharp fall in gas demand across all sectors, and not just in Europe, to offset the large decline in Russian pipeline supply to Europe. At the moment, there seems little sign of either happening.

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. Figure 1.2 compares TTF prices with coal and carbon prices. The coal price (ARA – Amsterdam, Rotterdam, and Antwerp) is adjusted for the relative efficiency of gas power plants to coal power plants and the relatively higher carbon costs of coal.

¹ Payne, J. and Zhdannikov, D. (2021). ‘Commodity traders face big margin calls as gas prices soar’. *Nasdaq*, 4 October. <https://www.nasdaq.com/articles/exclusive-commodity-traders-face-big-margin-calls-as-gas-prices-soar-2021-10-04-0>

Figure 1.2: TTF gas and Rotterdam coal prices (adjusted for carbon price) and ETS prices



Source: Argus Media, ICE. Forward curve at 26 July 2022

Note: ETS refers to the EU Emissions Trading System (ETS) price of carbon credits, in US Dollars per tonne.

In early 2019, as TTF prices declined, we saw them fall well below the adjusted coal price, and this continued in 2020 as the impact of COVID-19 put considerable downward pressure on prices. As a result, there was significant coal to gas switching in 2019 and in 2020 even some lignite to gas switching in Germany. The sharp rise in TTF prices in early 2021 might have been expected to lead to a significant loss of competitiveness of gas relative to coal. However, coal prices also rose sharply, although by less than the TTF price, but the EU ETS price also rose to provide a further boost to the carbon-adjusted coal price. Gas, therefore, maintained its competitive position, providing some support to gas demand in Europe through the middle of 2021.

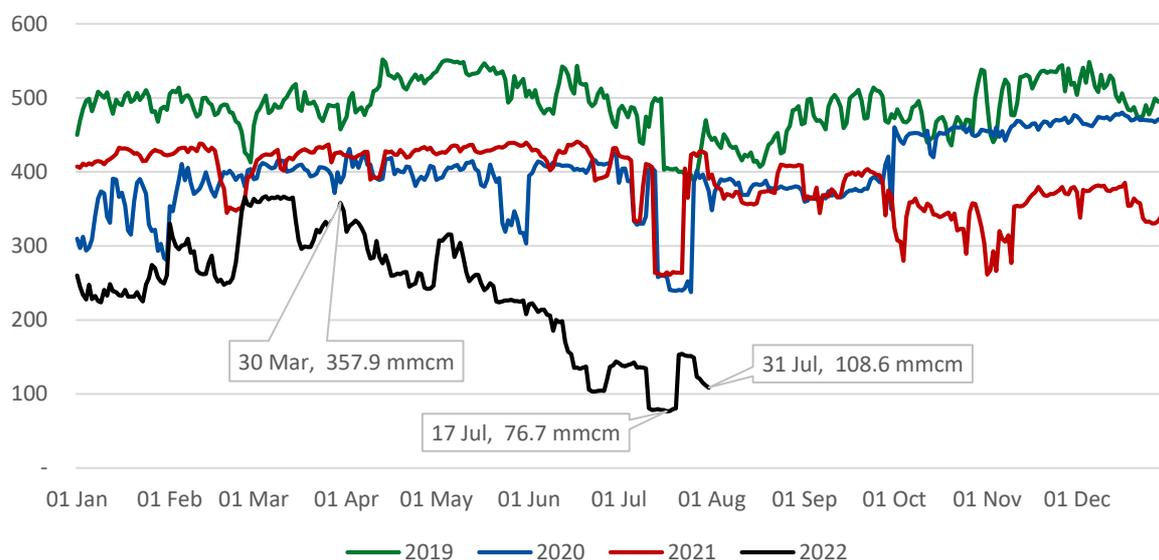
The rise in prices since August 2021, however, pushed gas prices well above the adjusted coal price, encouraging a switch to coal. The Russian invasion of Ukraine pushed gas prices a lot higher, but coal prices have also risen dramatically as well. However, gas prices are so high that there is still a large incentive to switch to coal in those markets where it is possible. Coal burn has certainly increased in Europe, but gas demand in power generation has not fallen as expected because of issues with nuclear plants, especially in France, and poorer renewables performance. The forward curves continue to show that, even when adjusted for the forecast carbon prices, coal will remain substantially cheaper than gas in power generation through 2023. This suggests that gas demand in power will remain curbed by the continued use of coal in power generation. Furthermore, if there is a recovery in nuclear power generation and better renewables performance, then gas demand in power in Europe could drop significantly, even without forced rationing in the event of a curtailment of Russian flows.

2. European gas market dynamics

2.1. Russian pipeline gas supplies to Europe

A major development in the second quarter of 2022 has been the decline in flows of Russian pipeline gas to the European market. In the previous two editions of the OIES Quarterly Gas Review, we noted the year-on-year declines in Q4-2021 and Q1-2022. Since then, the daily flow of Russian pipeline gas to Europe² fell from 358 MMcm/d on 30 March to a low of 78 MMcm/d on 16 July, during the period when Nord Stream was taken completely offline for maintenance. Flows recovered when Nord Stream came back online on 21 July, but fell again on 27 July, when another turbine was taken offline. As a result, Nord Stream is currently running with only one of its eight turbines operational, and flows of just over 30 MMcm/d (just under 20 per cent of the 165 MMcm/d capacity).

Figure 2.1: Daily Russian pipeline flows to Europe in 2022 (MMcm/d)



Source: Data from ENTSOG Transparency Platform. Graph by the author

Of the three major routes from Russia to Europe that have experienced a decline in the past twelve months, the Yamal-Europe pipeline (with flows measured on the Belarus-Poland border) was the first to exhibit such a decline. Flows of 94-95 MMcm/d between Q4-2020 and Q2-2021 fell to 28 MMcm/d by Q4-2021 and 11 MMcm/d in Q1-2022. In Q2-2022, flows on this route averaged just 4 MMcm/d, having come to a complete halt on 11 May.

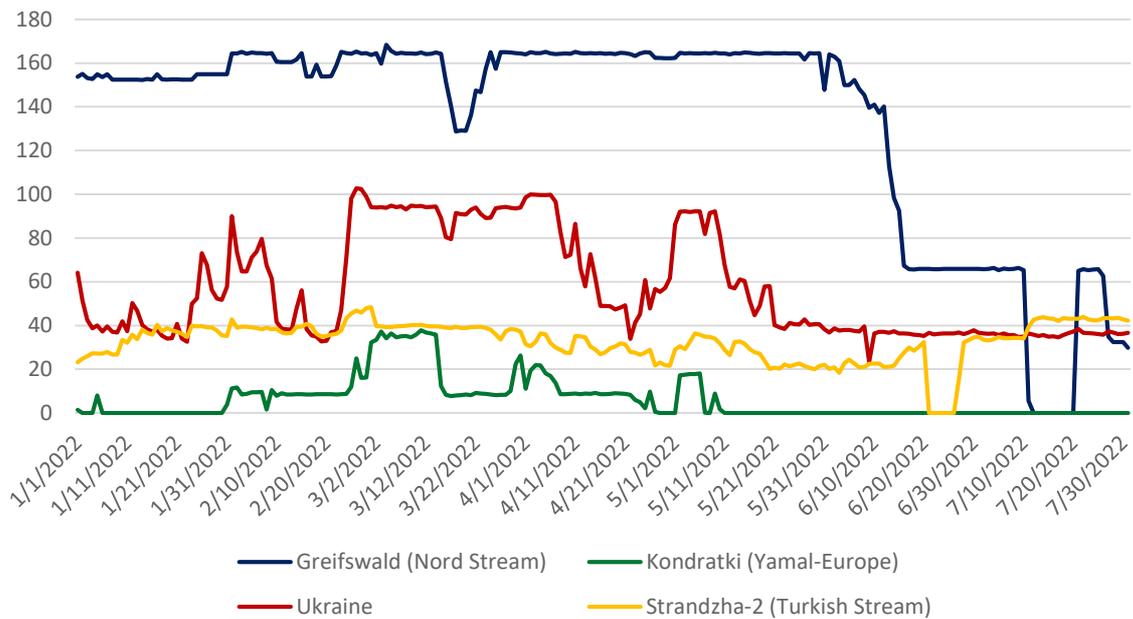
As recently as November-December 2021, gas transit via Ukraine averaged roughly 100 MMcm/d, before falling to 66 MMcm/d in Q1 2022, and 55 MMcm/d in Q2 2022. Between 21 May and 31 July 2022, exit flows to Europe (excluding Moldova) on Ukraine's western border averaged 37 MMcm/d.

Finally, the first step in the decline of Nord Stream flows occurred between 30 May and 12 June, with flows falling from 165 MMcm/d to 140 MMcm/d. The larger decline took place between 12 and 18 June, as flows fell to 67 MMcm/d. Flows remained at that level until they temporarily fell to zero during the 11-21 July maintenance period. The most recent decline occurred on 27 July, when Nord Stream flows fell to 35 MMcm/d, before dropping further to 30 MMcm/d on 31 July.

The only route to see stable flows in Q2-2022 was Turkish Stream. Gas delivered to Turkey via Turkish Stream flows onwards to south-eastern Europe (Bulgaria, Greece, North Macedonia, Serbia, and Hungary), and flows are measured at Strandzha-2 on the Turkey-Bulgaria border.

² EU plus UK and non-EU Balkans, but excluding Turkey

Figure 2.2: Daily Russian pipeline flows to Europe by route in 2022 (MMcm/d)



Source: Data from ENTSOG Transparency Platform.³ Graph by the author

The decline in flows of Russian pipeline gas to Europe in 2021 were analysed in an OIES paper by the present author in December 2021,⁴ while the slump in flows in January and resurgence in late February and early March, following Russia’s invasion of Ukraine, were analysed in the previous edition of the OIES Quarterly Gas Review.⁵ Here, it is sufficient to recall that in May, two key events took place in relation to Russian pipeline export capacity: 1) the Russian government placed sanctions in EuRoPol Gaz (the owner-operator of the Yamal-Europe pipeline in Poland), thus preventing Gazprom from using that route; 2) The Ukrainian Transmission System Operator, GTSOU, declared *force majeure* at Sokhranivka, one of the two cross-border interconnections with Russia, on the grounds that it had lost control of the gas metering station and nearby compressor station in the context of Russian military occupation, and local reports of unauthorised offtakes of transit gas.

A further decline in Gazprom’s pipeline export capacity took place before the end of Q2. In mid-June, Gazprom announced that the capacity of Nord Stream would be reduced, due to issues with turbines at the Portovaya compressor station. The legal and technical aspects of this issue have been examined in detail in a recent OIES Comment,⁶ as has the impact of the reduction of Nord Stream capacity on Russian pipeline gas flows to the European market.⁷ Here it is sufficient to note that the Portovaya compressor station consists of six large and two smaller turbines. When the capacity of Nord Stream was reduced on 17 June, two turbines remained in operation, with flows at around 67 MMcm/d. This configuration remained when Nord Stream resumed operation after maintenance, on 21 July. However,

³ ENTSOG, 2022. *Transparency Platform*. <https://transparency.entsog.eu/#/map>

⁴ Sharples, J., 2021. A Series of Unfortunate Events – Supply-side factors in the European gas price rally in 2021 and outlook for the rest of winter. *OIES Insight № 108*. <https://www.oxfordenergy.org/publications/a-series-of-unfortunate-events-supply-side-factors-in-the-european-gas-price-rally-in-2021-and-outlook-for-the-rest-of-winter/> (see pages 15-23)

⁵ Fulwood, M., Ouki, M., and Sharples, J., 2022. *OIES Quarterly Gas Review*, May 2022.

<https://www.oxfordenergy.org/publications/quarterly-gas-review-short-and-medium-term-outlook-for-gas-markets/>

⁶ Fulwood, M., Sharples, J., Stern, J., and Yafimava, K., 2022. The Curious Incident of the Nord Stream Gas Turbine. *OIES Energy Comment*, 20 July. <https://www.oxfordenergy.org/publications/the-curious-incident-of-the-nord-stream-gas-turbine/>

⁷ Sharples, J., 2022. *Falling Like Dominoes: The Impact of Nord Stream on Russian Gas flows in Europe*. [Forthcoming]

on 27 July, another turbine was taken offline, leaving only one operational, and flows dropped to 35 MMcm/d, before falling again to 30 MMcm/d on 31 July.

The remaining turbine at Portovaya may also be taken offline for servicing in the near future. Only one turbine from Portovaya has been successfully serviced by Siemens Energy at their facility in Canada, but that turbine is still not yet (at the time of writing) back in Russia ready for installation. On 28 July, Siemens and Gazprom blamed each other for the delay in delivering the turbine back to Russia.⁸ It is possible that the serviced turbine will be reinstalled just as the last turbine goes offline for servicing, perhaps in the first half of August. From that point onwards, it is not clear how long it will take to ship the remaining turbines to Canada, service them, bring them back to Russia, reinstall them at Portovaya, and raise flows via Nord Stream.

In relation to gas trading and supply under long-term contracts, two further key events took place in Q2 2022. Firstly, under threat of an antimonopoly investigation by the European Commission, Gazprom abruptly announced that it was withdrawing its participation in its European subsidiaries with immediate effect. This impacted Gazprom Germania (now under the temporary control of the German gas regulator, BNetzA, under the new name, Secure Energy For Europe, or SEFE) and its many subsidiaries. These included gas storage operators (such as Astora in Germany and Austria) and gas trading entities (such as Gazprom Marketing & Trading in the UK). As a result, Gazprom has effectively ceased trading in the European spot market, and therefore no longer provides gas to its trading subsidiaries, and no longer holds downstream storage capacity, and thus no longer flows gas to replenish its storage stocks.

A second factor is the consequence of the Russian Presidential Decree issued on 31 March 2022, requiring all of Gazprom's counterparties from 'unfriendly' countries to henceforth pay for their gas supplies in Roubles, rather than Euros or US Dollars. As a result, Gazprom cut off supplies to PGNiG (Poland) and Bulgargaz (Bulgaria) on 27 April, Gasum (Finland) on 21 May, GasTerra (Netherlands) on 31 May, and Ørsted (Denmark) and Shell Energy Europe (Germany) on 1 June. Supplies to Latvijas Gāze (Latvia) were cut on 30 July. In addition, Lithuania and Estonia announced the end of imports from Russia from 31 March.

Crucially, the decline in Gazprom's need for pipeline capacity (due to the cessation of spot trading, provision of gas to former subsidiaries, and supply of gas under long-term contracts to those who refused to pay in Roubles) was not as great as the actual decline in pipeline capacity (due to the Russian sanctions against the Yamal-Europe pipeline, reduction in transit via Ukraine, and reduction in Nord Stream capacity). As a result, Gazprom declared *force majeure*, citing the issue with the turbines, in relation to its provision of gas under long-term contracts to several of its counterparties, as Gazprom is currently not meeting its long-term contractual commitments to those counterparties.

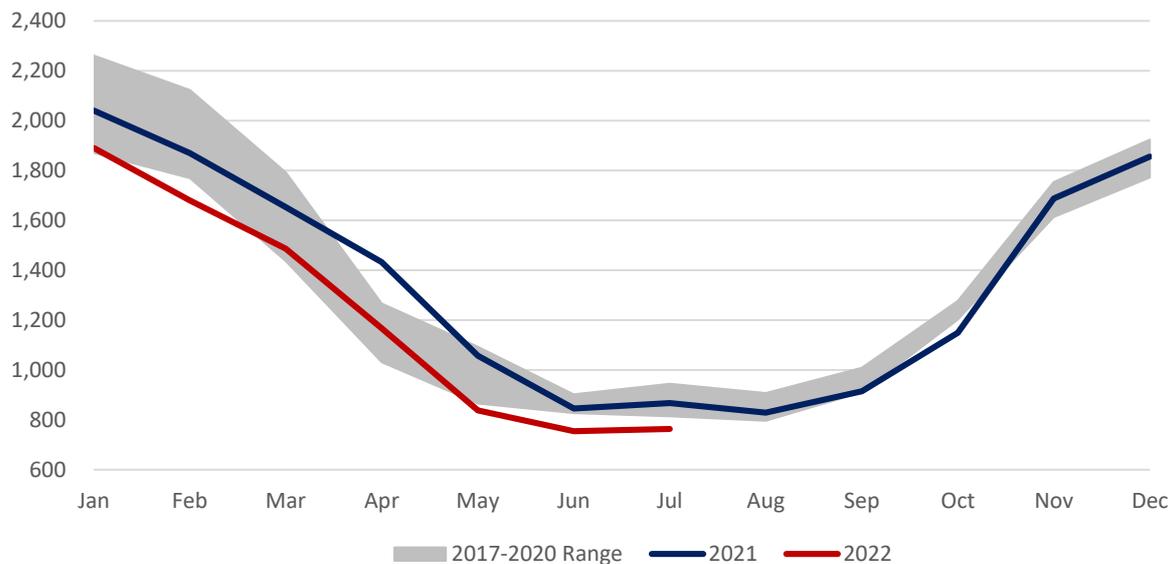
The market has reacted strongly to these developments, as noted in the price analysis in the first part of the Quarterly Gas Review. Looking forward, it seems likely that flows from Russia will remain constrained until the start of winter, with significant implications for both the European supply-demand balance and the accumulation of gas storage stocks ahead of winter, as analysed in the following two sections.

2.2. European supply-demand balance

Taking together European gas production, pipeline and LNG imports, and net storage withdrawals, it is possible to create a picture of implied consumption. As the graph below illustrates, this implied European consumption (in the EU and UK, but excluding Turkey), was below that of previous years (2018-2021) in Q1 2022. In Q2, implied demand did not exhibit the sharp drop in April as seen in 2018 and 2020, but followed the pattern of a gentler decline, as seen in 2019 and 2021. However, in May and June, implied European gas consumption once again fell lower than in the same two months in any year between 2018 and 2021.

⁸ Euronews, 2022. Russia's Gazprom, Siemens Energy at odds over turbine delay. *Euronews*, 28 July. <https://www.euronews.com/next/2022/07/28/ukraine-crisis-gazprom-nordstream>

Figure 2.3: Total supply to the European market (MMcm/d)



Source: Data from ENTSOG Transparency Platform, Eurostat, Kpler (LNG), and Gas Infrastructure Europe (Aggregated Gas Storage Inventory). Graph by the author. Note that 'Total Supply' refers to production plus pipeline imports plus LNG sendout plus net storage withdrawals

As discussed above, this decline in implied consumption is partly due to lower pipeline imports from Russia. In Q2-2022, pipeline imports from Russia (21.3 Bcm) were down by 17.4 Bcm (45 per cent) year-on-year. And, as discussed in the next section, it is also partly due to record storage injections between 1 April and 31 July (most recent data). In Q2-2021, net storage injections totalled 18.0 Bcm, compared to 32.8 Bcm of net storage injections in Q2-2022. With 17.4 Bcm less from Russia and 14.8 Bcm more injected into storage, this effectively took 32.2 Bcm off the market.

By contrast, pipeline imports from non-Russian sources in Q2-2022 were 3.8 Bcm (10 per cent) higher, at 41.1 Bcm. This included a 4.5 Bcm increase in supply from Norway and a 0.9 Bcm increase in supply from Azerbaijan, offset by a 1.6 Bcm decline in imports from North Africa. The rise in imports from Norway and Azerbaijan was effectively capped by pipeline, rather than production, capacity. The pipelines from Norway to the EU have continued to operate at close to full capacity since the start of winter 2021/2022, with high utilisation rates continuing into the present summer. It is only the flow via the Langeled pipeline to the UK (which has alternative supplies from its own production and in the form of LNG) that has tailed off since the end of winter.⁹ At the same time, the year-on-year increase from Azerbaijan reflects the fact that in Q2-2021, the Trans-Adriatic Pipeline (TAP) was still ramping up flows, following its launch at the beginning of the year. The TAP reached full capacity in Q4-2021, so no year-on-year increase of supply from that source can be expected at the start of winter. Pipeline supply from Algeria is partly constrained by the cessation of transit flows to Spain via Morocco in late 2021. However, given that Algerian LNG exports are also lower year-on-year and that there is spare capacity on the Algerian pipeline route to Italy, the lower pipeline flow from Algeria to Europe appears to be due to constraints in Algerian gas production relative to domestic demand.

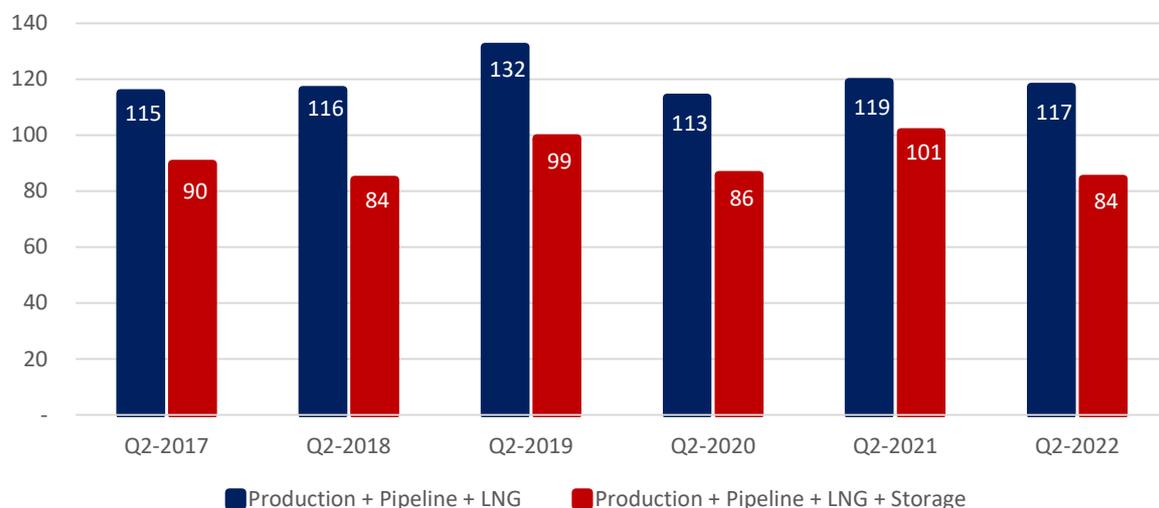
With European gas production in Q2-2022 just 1.4 Bcm (8 per cent) higher year-on-year, at 18.8 Bcm, it has been left to higher LNG imports to fill the gap left by lower pipeline imports from Russia and Algeria and higher storage injections. For context, LNG sendout in Q2 in 2019 (28.1 Bcm), 2020 (26.4 Bcm), and 2021 (25.7 Bcm) was relatively consistent year-on-year. By contrast, in Q2-2022, European LNG sendout totalled 36.0 Bcm. This was not only significantly higher than Q2 sendout in previous years, but also 0.6 Bcm higher than in Q1-2022.

⁹ Gassco, 2022. *Historical Nominations*. <https://umm.gassco.no/ch/>

The first two quarters of 2022 were the only quarters in which European LNG sendout has been greater than 30 Bcm. Q2-2022 was also notable regarding the difference between LNG import and LNG sendout volumes. In Q2-2022, LNG imports were 2.8 Bcm higher than sendout, implying substantial stockbuild. In Q2-2021, the difference between LNG imports and sendout was just 1.4 Bcm, similar to differentials seen in 2017, 2018, and 2020. In the year to date (Q1 + Q2 2022), European LNG imports have been 74.5 Bcm, up from 48.5 Bcm in H1-2021, and 29 per cent higher than the previous record of 57.9 Bcm imported in H1-2020, when the European market absorbed substantial volumes from a significantly oversupplied global LNG market at a time of record low prices.

Overall, the gross supply to the European market (production plus imports) in Q2-2022, at 117 Bcm, was not dramatically different to that seen in Q2 in the previous five years, with the exception of 2019. When net storage injections are taken into account, the balance in Q2-2022 (84 Bcm) is not very different from those seen in Q2 in 2018 and 2020. However, the pricing environment is absolutely different. This may be reflective of two factors: firstly, the fact that European demand is met by LNG sourced from the global market to a far greater extent than in previous years (implying that high prices are necessary to attract spot cargoes that help to balance the market), and secondly the geopolitical context, in which there is market concern over the dependability of supply from a major source (Russia) ahead of the coming winter.

Figure 2.4: Supply to the European market in Q2, with and without net storage injections (Bcm)



Source: Data from Eurostat, ENTSOG Transparency Platform, Gas Infrastructure Europe (Aggregated Gas Storage Inventory), and Kpler LNG Platform (subscription required)

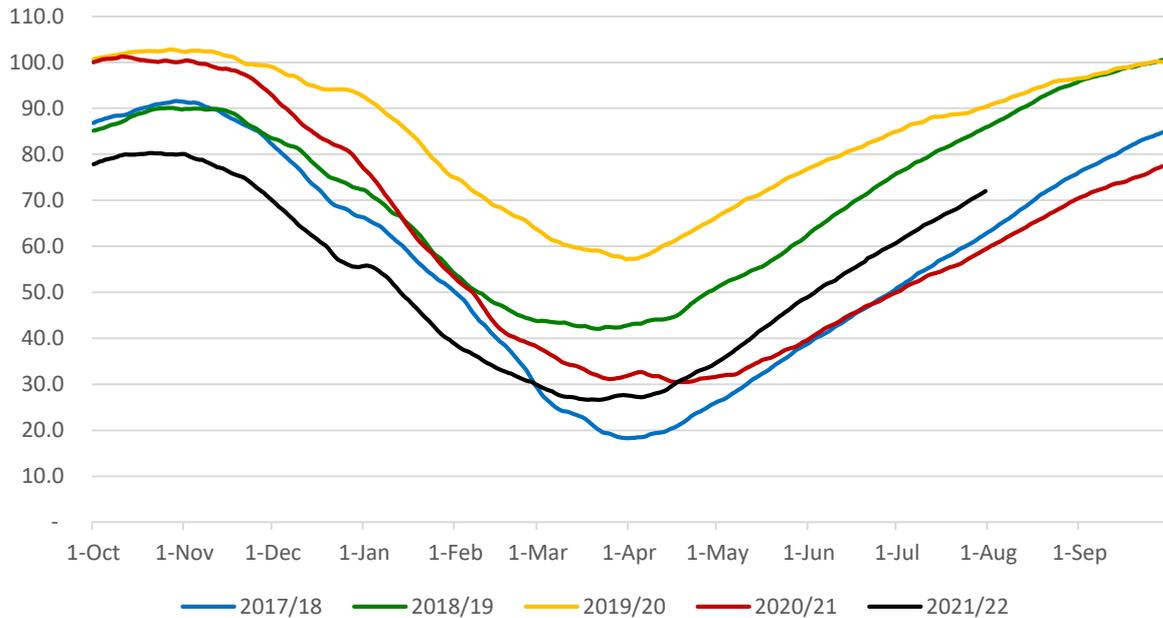
2.3. European gas storage

First, the good news. As recently as 27 February 2022, European gas storage stocks were lower than on that date in any of the preceding five years. However, strong injections since the end of winter changed the situation. The net injection into storage between 1 April and 31 July (latest data) was 44.5 Bcm – a new record. This is slightly higher than the 44.4 Bcm injection in that period in 2018 (in the aftermath of ‘The Beast from the East’) and the 43.0 Bcm injected in that period in 2019, as Europe was absorbing LNG from an increasingly supply-long global market, while Russian pipeline supplies were also building towards record exports to Europe (excluding Turkey) in 2019.

As a result, European storage stocks on 31 July stood at 72.0 Bcm (69 per cent of storage capacity). The official European Commission target is for EU storage stocks to be 80 per cent of capacity (83 Bcm) by 1 November, although some EU member states, such as Germany, have set higher targets. That EU target implies injections of 11.0 Bcm in the 93 days between 31 July and 1 November, at an average rate of 118.3 MMcm/d. In the 93 days between 30 April and 31 July, Europe injected 37.6 Bcm, at an average rate of 404 MMcm/d. Even while Nord Stream was entirely offline for maintenance in the period 12-20 July, European storage injections averaged 325 MMcm/d.

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Figure 2.5: European gas storage stocks (Bcm)



Source: Data from Gas Infrastructure Europe Aggregated Gas Storage Inventory.¹⁰ Graph by the author

And now the bad news. European storage injections have been made possible by lower summer demand, which is influenced by both warmer temperatures and the prevailing high prices. European injections have also been made possible by the record European LNG imports, which were partially assisted by lower LNG demand outside of Europe, namely in China. As the northern hemisphere moves into the winter period, temperatures will fall and LNG demand will rise. LNG supply to Europe may become less plentiful just at the moment when European gas demand begins its seasonal increase. This will leave less gas for injection into storage. If Europe is going to achieve, and even exceed, its 80 per cent storage target, most of the injections need to be made before the winter begins.

Net injections at the mid-July rate implies the injection of 1 Bcm every three days, meaning that the 80 per cent storage target could be met in 33 days – by 2 September. If that rate of injection is continued, a further 10 Bcm could be injected in September, and another 10 Bcm in October, taking European storage close to full capacity. Given the concerns over the flow of pipeline gas from Russia, and uncertainty over prevailing temperatures (and related demand) during the coming winter, every additional cubic metre held in storage at the start of winter is valuable.

In reality, it is unlikely that injections will continue at a rate of 1 Bcm every three days in September and October, not least due to rising seasonal demand at the start of winter. Furthermore, with pipeline flows from Russia currently even lower than in the first part of summer, these being in no small part influenced by the decline in flows via Nord Stream, it remains to be seen whether the present rate of injection is maintained through the rest of summer.

A plausible outcome is that the EU storage target is met in late September, and that only a relatively small volume of additional injections is made in the last five weeks before the 1 November target. While the primary target is reaching 80 per cent of capacity as soon as possible, the time period between the attainment of that target and the start of net withdrawals will be an uncertain one, with market sentiment reacting to both the length of that time period (the longer injections continue the better) and the volume of daily injections made during that period (the higher the better).

Dr Jack Sharples, Research Fellow, OIES

¹⁰¹⁰ Gas Infrastructure Europe, 2022. *Aggregated Gas Storage Inventory*. <https://aqsi.gie.eu/historical/eu>

3. In the bleak midwinter: EU plans for reduced gas consumption

On 26 July, the Council of European Union issued a package of voluntary reductions in gas demand.¹¹ The reductions are suggested to take place in the coming winter (between 1 August 2022 and 31 March 2023), with the target being that gas consumption in that period should be 15 per cent lower than the average winter gas consumption for the previous five years. The package was somewhat watered down from the one published a week or so earlier, following objections by a number of member states. There are now some exemptions and derogations for those member states which a) have no or limited interconnections with other member states; b) have overshot their gas storage filling targets; c) are heavily dependent on gas as a feedstock for critical industries; or d) have seen their gas consumption increase by at least 8 per cent in the past year compared to the average of the past five years. This provides a number of ways to opt out.

The 15 per cent reduction in gas demand is a possible response to lower pipeline flows from Russia. This is not necessarily a complete curtailment, but a reaction to potentially limit the damage to EU gas markets and economies, especially for the winter period, to flows continuing at very low levels. However, a complete curtailment clearly cannot be ruled out. If there was a complete curtailment to EU countries what might the impact be?

We have used the NexantECA World Gas Model to consider a scenario where there is a complete curtailment of Russian flows on Nord Stream and through Ukraine to European countries, starting on 1 October 2022. Looking at the first whole year (2023) this results in a reduction in gas demand in EU countries of some 15 per cent compared to what it would otherwise have been in the Control Case. The Control Case assumes Nord Stream flows return to maximum capacity in 2023 but are lower for the rest of this year (2022) at levels close to the pre-July maintenance rates, and flows via Ukraine remain broadly at June 2022 flow rates. Together with flows down Turkish Stream to EU countries, this would be broadly consistent with these countries taking the take-or-pay levels under the remaining long-term contracts with Gazprom. In 2023, this amounts to just over 70 Bcm.

In the Control Case, it is just possible that Europe might muddle through this winter, with a few caveats. The winter is mild, there are no more disruptions to LNG supply, and that Asian LNG demand, especially China, does not rebound back strongly, thereby allowing continued strong LNG flows to Europe. Any increased tightness in the LNG market, and especially a cold winter, would test the European market and would likely lead to demand rationing.

The 15 per cent reduction, in the No Russian Flows Case, is a 58 Bcm decline. However, EU gas demand in the Control Case in 2023 was already 28 Bcm lower than in 2021. Part of this fall is weather-related as 2021 contained a cold winter, but at least half is induced by high prices, which are expected to remain, even in the Control Case. The overall fall between 2021 and 2023, if Russia flows are cut off in 2023, is estimated at some 86 Bcm – a decline of some 20 per cent.

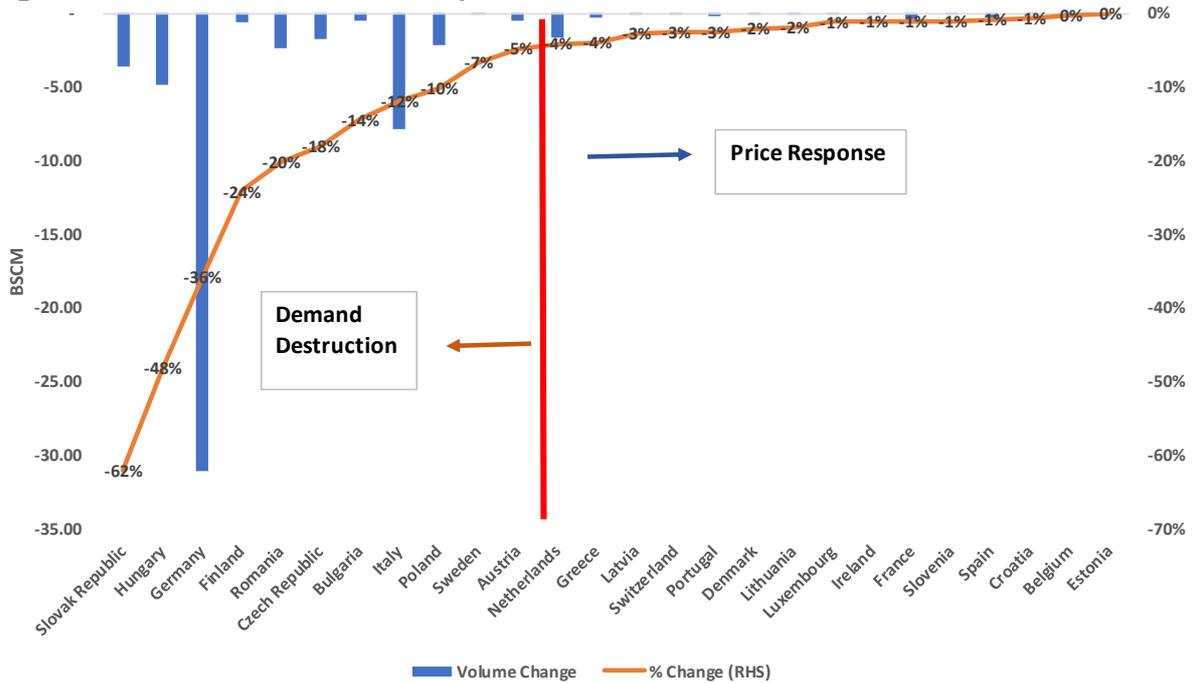
The problem is that the EU's voluntary reductions in gas demand of 15 per cent are intended to be 'across the board' at least for those countries which participate, after the exemptions and derogations. The curtailment of Russian flows, on the other hand, impacts only a small group of EU countries directly in terms of a gas shortage, even though the whole world is impacted by high prices. The figure below illustrates the reduction in gas demand by EU country for 2023 if Russia flows are stopped compared to the Control Case.

There are very large reductions in those countries heavily dependent on Russian gas, with few alternatives. Slovakia has a 62 per cent decline, Hungary 48 per cent, Germany 36 per cent, with Finland, Czech Republic and Romania all around 20 per cent. Italy also has a decline of 12 per cent, and Poland 10 per cent. Of the 58 Bcm decline in EU demand, 31 Bcm is from Germany, so some 55 per cent of the total reduction. The next highest volume decrease is Italy at 8 Bcm and then Hungary and Slovakia at some 4 to 5 Bcm. Generally, those countries to the right of the red line in the figure

¹¹ <https://www.consilium.europa.eu/en/press/press-releases/2022/07/26/member-states-commit-to-reducing-gas-demand-by-15-next-winter/>

below will largely see reduced demand due to price impacts, while those to the left are faced with a shortage of gas and demand destruction.

Figure 3.1: No Russia flows to EU impact 2023



Source: NexantECA World Gas Model, OIES estimates

The idea behind the EU’s more evenly spread reduction is EU solidarity amongst member states, although Hungary rejected the package totally. The big problem behind EU solidarity is that the interconnections and capacity limitations between EU member states do not facilitate the sharing of large hits to gas demand. There is little or nothing that Spain, Portugal, Greece and even Belgium and France can do to assist Germany and other central European countries, with additional gas by cutting their own needs by 15 per cent. The pipeline infrastructure and capacity doesn’t exist to move large quantities of gas eastwards. Only the Netherlands might be able to assist Germany and then onwards to the Central European countries, and this happens to some extent in the No Russia Flows Case.

With the largest decline in volume terms, Germany is an interesting case study of the impact. Pipeline imports (net) are down some 42 Bcm in 2023 compared to the Control Case, and 55 Bcm compared to 2021. LNG terminals are expected to open up in 2023 and in the No Russia Flows Case some 13 Bcm of LNG is imported, the maximum capacity of the terminals, which is higher by 8 Bcm than in the Control case. As noted above, German demand is 3 Bcm lower than in 2023 with no Russian flows, and compared to 2021 is some 44 Bcm lower. The reduction in demand is almost totally in power generation and industry. With no Russian flows, there is no gas available for use in the power sector, while industrial use is 50 per cent lower than in 2021. The residential and commercial sectors are largely protected from any significant reductions. The table below illustrates the impact on neighbouring countries to Germany as well.

Table 1: No Russia flows impact (% change 2023 v 2021)

BSCM		2021	2023	
			Control	No Russia
Germany	Power	23.2	24.4(5%)	1.0(-96%)
	Industry	30.7	25.5(-17%)	16.7(-46%)
Slovakia	Power	0.7	0.9(19%)	0(-100%)
	Industry	2.2	2.6(19%)	0(-100%)
Hungary	Power	2.8	2.3(-15%)	0(-100%)
	Industry	3.0	3(0%)	0.4(-85%)
Czech Republic	Power	1.9	2(6%)	0.4(-78%)
	Industry	3.1	3.6(17%)	3.5(13%)

Source: NexantECA World Gas Model, OIES estimates

Some growth in gas demand in 2023 over 2021 might be expected in the Control Case in power and industry. However, with no Russian flows then gas demand in power is almost completely eliminated in all countries and industry is badly hit in Slovakia and Hungary, and Germany down almost 50 per cent, as already noted. The large reductions in power and industry reflect the full protection given to residential and commercial heating load in particular. To the extent that policy measures and savings reduce demand in the buildings sectors, more gas could be available for the power and industry sectors.

The EU's objective to share the pain of a scenario where Russian flows of gas to the EU remain low or are curtailed completely, is laudable. However, the reality is that the countries hit hardest will be those heavily exposed to Russian flows. Even with Germany constructing new LNG terminals, these cannot replace the reliance on Russian pipeline gas in the short term. Any LNG coming to Germany is diverted from other markets, until more LNG supply comes on in the mid to late 2020s. Germany, Slovakia, Hungary, and the Czech Republic are potentially faced with devastating demand destruction this winter and through 2023. Finland, Romania, and Bulgaria are also badly hit during the coming winter period. Italy and Poland may be faced with 10 per cent lower demand, but this may be more manageable with some planned demand reductions. The situation in Poland will be significantly worse if the new Baltic pipe from Norway via Denmark is not operational this winter since, with no Russia flows, the prospects of importing from Germany via Mallnow are limited.

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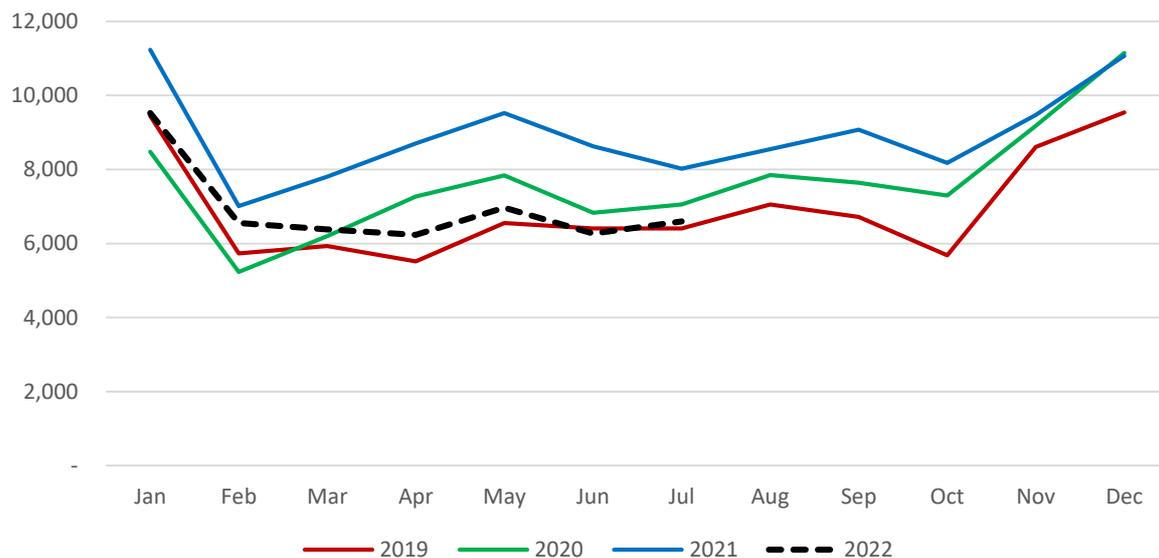
4. China's gas demand: not just a question of weather

Following stringent lockdowns in Shanghai and ongoing COVID-related restrictions all over China since May, China's GDP growth in Q2-2022 was a modest 0.4 per cent year-on-year, falling from its 4.8 per cent year-on-year growth in Q1-2022.

As a reflection of the weak macro environment, China's implied gas demand was considerably weaker in H1-2022, falling by 4 Bcm year-on-year, or 2 per cent. While domestic production and pipeline flows increased, LNG imports contracted sharply, by 12 Bcm (or 22 per cent) year-on-year. A combination of weak industrial activity alongside the availability of coal and hydropower for power generation were among the key factors behind China's limited appetite for LNG. In June, overall power demand rose by 23 TWh (3 per cent) year-on-year, from 686 TWh in June 2021 to 709 TWh in June 2022 (after a 3 per cent year-on-year drop in May). Stronger renewable generation is helping to meet demand, likely curbing the call on China's gas-fired fleet.

High spot prices further contributed to weak LNG imports, although as of April 2022, average LNG costs reported by China customs were \$13/MMBtu, with US and Russian LNG arrivals reported at above \$20/MMBtu. Between January 2016 and November 2021, China's monthly LNG imports grew year-on-year in every month except October 2019 and January-February 2020. However, China's monthly LNG imports were lower year-on-year in every month from December 2021 to July 2022.

Figure 4.1: China's monthly LNG imports (MMcm of natural gas equivalent)



Source: Data from Kpler LNG Platform (subscription required). Graph by the author

After the downbeat macroeconomic performance in Q2-2022, market expectations of a strong stimulus have increased. But a slow recovery is more likely than a strong rebound even as the central government opens the fiscal taps. Local officials are still wondering how to balance economic growth, environmental protection and zero-COVID.

The government's COVID strategy is, however, evolving. Control measures are slightly less stringent than before, lockdowns do not necessarily confine people to their homes, while domestic travel restrictions are being relaxed and some local authorities are scaling back testing due to funding shortages. International flights are increasing and quarantine rules for international travellers are also easing.

On 30 June, the State Council announced that 300 billion yuan (\$45 billion) will be raised through financial bond sales and other methods to fund infrastructure projects. The arrangement comes in addition to an 800-billion-yuan increase in policy banks' lending quota announced on 1 June, also to support infrastructure investment.^{12 13}

According to China's Central Bank, the 300 billion yuan will mainly be used to invest in transportation, water conservation and energy networks; industrial upgrades such as logistics and technology; urban infrastructure such as underground pipe networks; agricultural and rural infrastructure as well as the more nebulous category of national security infrastructure.

¹² Reuters, 2022. China will hike credit quota for policy banks to support infrastructure - state media. Reuters, 1 June. <https://www.reuters.com/article/china-economy-stimulus-idINB9N2XF00B>

¹³ Bloomberg, 2022. What Are the Policy Banks China Uses to Spur Economy? Bloomberg, 30 June. <https://www.bloomberg.com/news/articles/2022-06-30/what-are-the-policy-banks-china-uses-to-spur-economy-quicktake>

But even as the economy continues to open, a strong rebound will remain elusive. Restrictions vary by province and even city, so navigating the various control regimes is challenging. Moreover, opening up could lead to higher infection rates, which will either lead to renewed restrictions or to worker absences that will weigh on economic activity.

Given that the industrial and commercial sectors are the biggest consumers of gas in China, the outlook for demand relies heavily on industrial activity in the second half of the year. A weather-induced uptick in imports, alongside an increase in industrial activity could support gas demand in the second half of the year, but LNG imports are still unlikely to match 2021 levels. As a result, even with ongoing increases in domestic production and higher pipeline flows—with arrivals through the Power of Siberia expected to rise by 5 Bcm from 2021 levels—demand may fall short of 2021's very high levels.

Even the power sector, a growing source of gas consumption, may see demand capped by the availability of coal, hydropower—buoyed by above-average rainfall in the year-to-date—as well as additional renewable capacity. With several provinces already experiencing peak demand due to the heatwave in parts of China, short spikes in demand, including for gas in the power sector, are possible.

Even though more coal has been mined in China this year (an 11 per cent year-on-year increase in H1-2022), and power generation recovered in June, putting it marginally higher than H1-2021 levels—albeit by 1 per cent—thermal power generation, which is primarily coal-fired, fell by 4 per cent compared to H1-2021. Meanwhile, hydropower, wind and solar generation grew by 20 per cent, 14 per cent and 7 per cent respectively year-on-year.

Moreover, after a coal mine accident in Gansu province, inspections of coal mine safety could slow output while peak power demand will require all fuel sources to meet the shortfall. Demand for gas-fired power generation in east and south China is therefore set to rise, but with industrial demand only recovering slowly, the demand spike will likely be short-lived.

China's limited gas storage is, for now, still full. But depending on the length of the heatwave and demand over the summer, buyers may need to restock ahead of the winter. What is more, several new LNG terminals are set to start up before winter, ahead of peak demand season in Northern China. The 5 mtpa Tangshan LNG, Hebei province, is expected to be operational in November. Meanwhile, Beijing Gas' 5 mtpa Tianjin Nangang terminal is also set for completion in November.

A cold winter will lead to steeper buying from China's importers, even if prices are high, but notwithstanding these temporary jumps, until the economy bounces back more significantly, gas demand growth is likely to be muted, as will LNG imports.

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