October 2023

Quarterly Gas Review: Gas Markets in 2023 Tracking Key Metrics

Introduction

In this fourth edition of the Gas Quarterly for 2023 we once again review the series of signposts that we outlined as key indicators of the global gas market during the year and also draw some conclusions about the outlook for prices and the supply-demand balance. In summary, our key conclusions are:

- Gas prices in Europe and Asia have been affected by contradictory forces over the past three months and into the northern hemisphere winter. On a bearish note, storage in Europe is now close to being full while the weather remains relatively warm, meaning that the market is now well supplied and there is even the possibility of LNG being turned away from the region. On the flip side, though, geopolitical concerns about the Russia-Ukraine war and the conflict in the Middle East have sparked worries about potential supply disruptions which have been compounded by the threat of strikes at LNG plants in Australia. The overall effect has been to push both spot and forward prices significantly higher in October, underpinning the point that the global gas market remains fundamentally tight despite the storage situation in Europe.
- As far as Russian supply is concerned, Europe (EU+UK) seems to have reached a new normal which has seen 78MMcm/d delivered via the Ukraine and Turk Stream routes combined in the first three quarters of 2023. This equates to 25 Bcm per annum, far below the 62 Bcm delivered in 2022 and the 178 Bcm delivered in 2019 pre-COVID. This has not only forced a huge diversification of European gas supply but has also reduced the flexibility in the European system to respond to supply shocks, implying greater future price volatility.
- Underlining this point, the continued fluctuations in Norwegian supply due to extended maintenance in Q3 have been another reason for the significant price swings mentioned above. However, the expectation is that supply will return to “normal” levels in Q4, bringing some relief to the market.
- Global LNG supply continues to be higher than in 2022, but growth has been slower than expected. To date the supply increase has largely come from the return of plants that were out of action in 2022 or from the ramp-up of new facilities, while new projects have been delayed and there has also been unforeseen maintenance at other plants. The result is that total output is up by 8 Bcm year-on-year, but this is half the growth seen in 2022 at the same stage of the year.
- Asian LNG demand growth has been a tale of two halves. In the first half of 2023, the overall levels of demand were only flat compared to 2022, having started the year very weak, However, Chinese and Indian demand have surged in Q3, and when combined with the continued growth in South-East Asia the overall total for the Asian region is now 3.5 Bcm (1.4%) above 2022 for the first 9 months of the year. Japan remains the only country with a major decline, due to nuclear restarts, but overall further growth in demand in Q4 is likely to add further pressure to the global gas market.

- By contrast, demand in Europe remains consistently lower in 2023 that in 2022 on a monthly basis, although the decline slowed to just -3 per cent year-on-year in August, and the year-on-year decline may even remain at that level in October. As a result, the level of gas in storage rose to an all-time high of 102 Bcm at the beginning of winter (defined as 1 October) and much will now depend on the temperatures as winter progresses. If the mild weather from winter 2022/23 is repeated, then injections could continue into November, which, given that EU storage facilities are almost full, would imply further injections into Ukrainian storage facilities. Higher volumes in storage could help to balance an otherwise tight global market in winter 2023/24. However, if it gets cold then prices could spike further.
- As far as the outlook for the next two or three winters in the European gas market is concerned, the themes discussed above are likely to remain critical and the level of storage at the start and end of the period will be closely watched. Our belief is that if gas in European storage is at 60 Bcm or above on 1st April 2024 then it will be relatively easy to refill it by the start of winter 2024/25. However, if the winter of 2023/24 is cold and stocks are well below 60 Bcm on 1st April 2024, then the situation will be more critical and prices could rise during a heavy period of summer injections.
- This situation will persist until the expected new wave of LNG supply comes online in 2025-26. Before then, any supply interruptions or surges in demand would have a significant impact on prices in a market with less inherent flexibility due to the loss of Russian long-term contracts with their take-or-pay element. As a result, the threat to the Ukraine transit contract, which expires at the end of 2024 and is unlikely to be renewed in its current form, is a critical issue even though only 10-12 Bcm per year is flowing through the Ukrainian system to the EU. The loss of even such a relatively small volume – around 3 per cent of a European (UK+EU-27) market with implied consumption of 414 Bcm in 2022 – would have a major impact in a cold winter 2024-25, although in subsequent winters its impact would be lessened by the emergence of more LNG onto the market.

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).

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1. Revisiting our signposts for 2023

In this first section of the quarterly review, we include our regular review of some key drivers for the global LNG market as well as for the European and Asian gas markets.

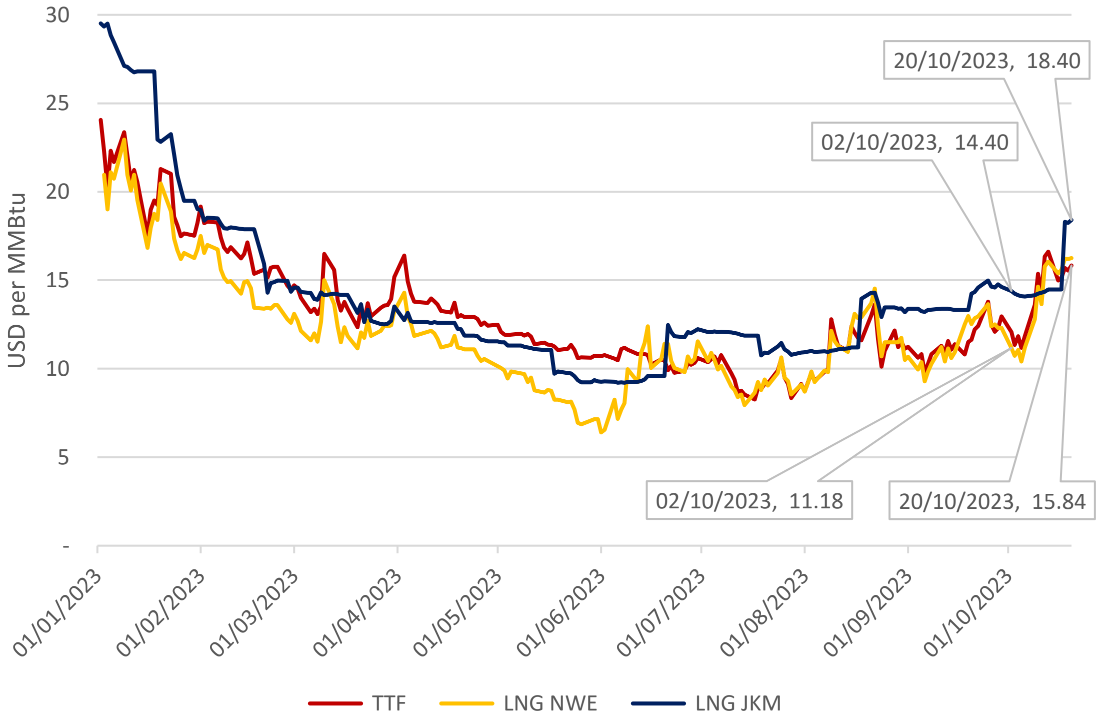
Gas prices

The previous Quarterly Review noted the continuous decline in TTF front-month prices, settling at around 10 USD/MMBtu at the end of June, as European gas demand remained notably lower year-on-year throughout H1.

Moving into Q3, TTF front-month prices dipped again to lows of 8-9 USD/MMBtu between 12 and 19 July, reflecting the expectation of the return in August of Norwegian pipeline supply that had been curtailed by maintenance from late April to mid-July. If all had remained stable on the supply side, one could have expected a further decline in prices through into August, as European storage facilities moved closer to full capacity.

In August, the expectation of further Norwegian supply curtailments in September lifted prices, and this was exacerbated by the news in early August that Australian LNG output could be impacted by industrial action. With LNG now accounting for a substantial proportion of European gas supply, and playing the role of marginal supply to the European market, any news that could signify a tightening of the global LNG market is bound to impact European forward prices.

Figure 1.1: Benchmark gas prices (TTF, Argus LNG North-West Europe, and S&P Global JKM for North-East Asia), Front-Month, US$/MMBtu

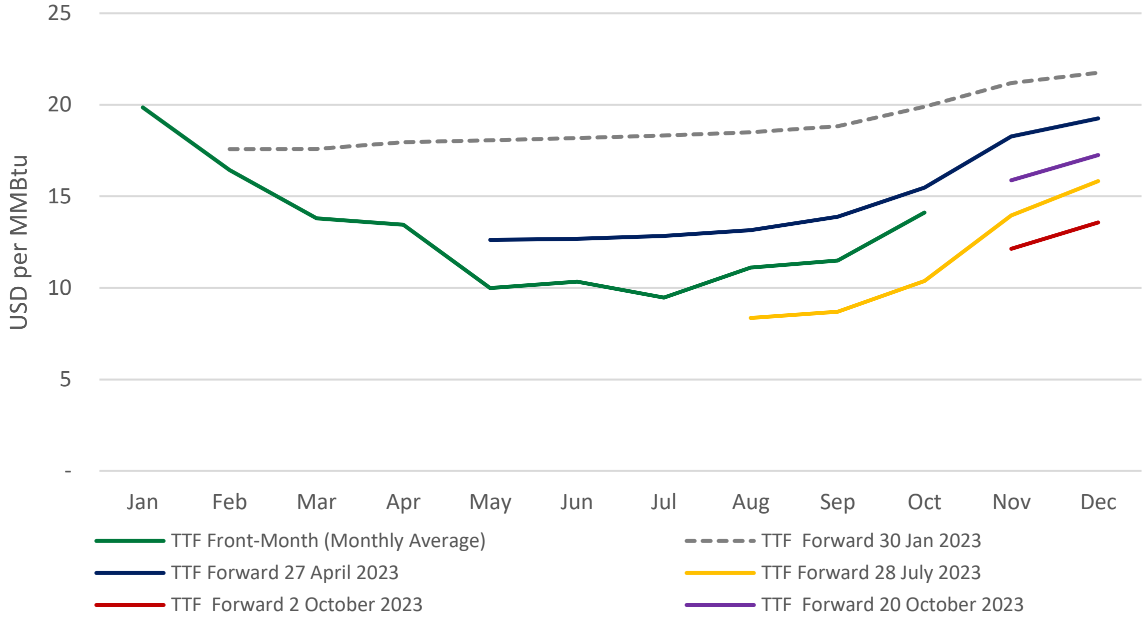


Source: Argus Media (LNG North-West Europe)[1] and Refinitiv/S&P Global (TTF and JKM).[2] Data labels for TTF and LNG JKM.

[1] Argus Direct (subscription required). https://direct.argusmedia.com/

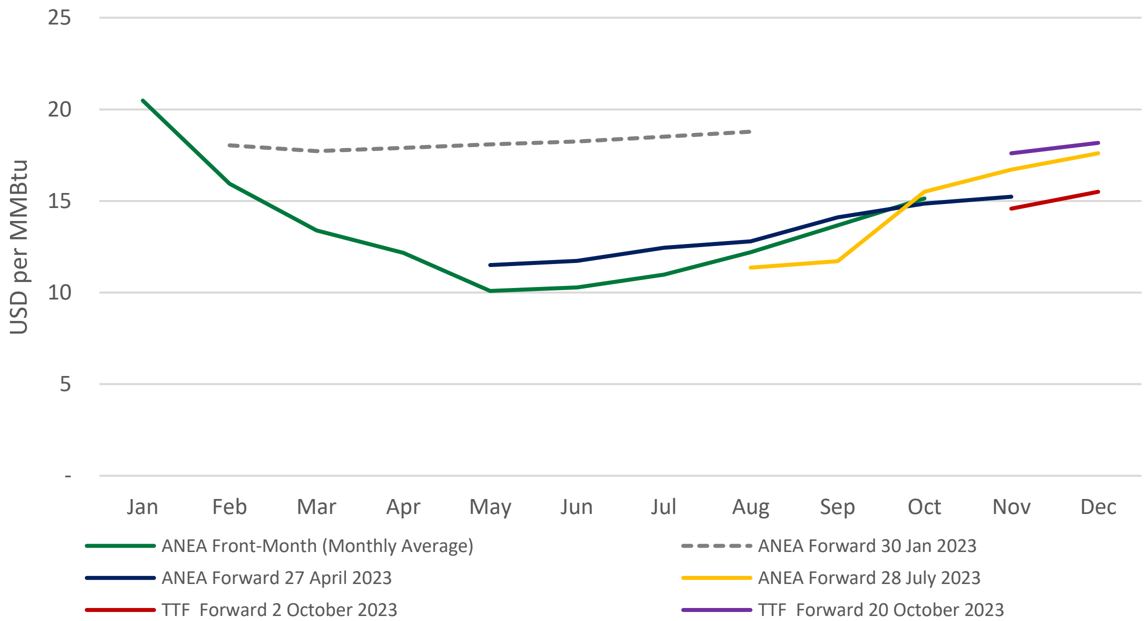
[2] S&P Global/Refinitiv (subscription required).

Figure 1.2: TTF actual front-month prices (to 20 October 2023) and forward prices as at various dates throughout the year to date



Source: Data from Argus. Graph by the author

Figure 1.3: Argus North-East Asia (ANEA) price assessments: actual front-month prices (to 20 October 2023) and forward prices as at various dates throughout the year to date



Source: Data from Argus. Graph by the author

The shift in market sentiment throughout the year to date can be illustrated by the forward prices at TTF and in North-East Asia. The dates chosen in the graphs above reflect the publication dates of our Quarterly Gas Review reports. As shown in Figure 1.2, the monthly average TTF front-month on January 2023 was around 20 USD/MMBtu. At the close of trading on 30 January, the forward prices for gas delivered between February and September showed a steady increase from around 17.60 USD/MMBtu to around 18.80 USD/MMBtu, reflecting a relatively bullish outlook for the summer of 2023.

By 27 April, TTF front-month prices had come down, but the forward prices suggested a market outlook that did not expect prices to decline further in the rest of summer, although the forward prices for delivery in Q4 2023 were markedly lower than they had been at the end of January. By 28 July, the TTF forward prices were more bearish still, with EU-27 storage stocks having reached 85 per cent of capacity.

By 2 October, the TTF prices for delivery in November and December 2023 were even lower than on 28 July, having risen slightly in August, and before falling back again in September. However, early October saw TTF front month prices rise by 52 per cent from 11.16 USD/MMBtu on Thursday 5 October to 17.01 USD/MMBtu on Friday 13 October, before settling back around 15 USD/MMBtu on 16-20 October. This was at least partly due to geopolitical concerns in two areas: the closure of the Balticconnector pipeline between Finland and Estonia on 8 October, amid suspicion of deliberate damage, and the suspension of gas production at the Tamar field in Israel on Monday 9 October, which led to a halt in Israeli pipeline exports to Egypt the following day. Given Egypt's dependence on pipeline imports from Israel to support its own domestic production, this will likely delay the restart in substantial LNG exports from Egypt until production at Tamar is restarted. In addition, on 9 October, Chevron Australia received notice of planned strike action at the Gorgon and Wheatstone LNG export facilities from 19 October, although the planned strike did not take place as the relevant unions reached agreement on 18 October.

In Asia, a similar trend was observed, with the Argus North-East Asia (ANEA) price assessment showing prices declining from January to May-June, before rebounding steadily through the remainder of summer and on to 20 October. Specifically, the ANEA front-month price of 18.03 USD/MMBtu on 30 January fell to 11.50 USD/MMBtu on 27 April and 11.36 USD/MMBtu on 28 July, before rising again to 14.58 USD/MMBtu on 2 October and 17.60 USD/MMBtu on 20 October.

A major point of difference between TTF and ANEA in the year to date is that while the ANEA forward prices for October delivery were fairly similar on 27 April and 28 July, on TTF there was a wide differential between the October delivery prices on 27 April and on 28 July. In short, European market sentiment regarding the supply-demand balance in October became markedly more bearish between late April and late July, while this did not appear to be the case in Asia.

In Europe, October is a time when storage stocks are reaching their peak and the uptick in winter seasonal demand has not yet begun. In Q3 2023, we saw storage filling to a high level, thus raising the prospect of short-term 'oversupply' that was expected to dampen October prices. Hence, European forward prices for October becoming more bearish as storage stocks grew during the summer. In Asia, where storage provides a far smaller share of winter supply than in Europe, the risk of short-term 'oversupply' in the shoulder month before the onset of winter is much reduced.

Looking forward to November-December 2023, the forward prices on TTF for delivery in those months became successively more bearish between late April, late July, and the beginning of October, before rebounding in mid-October. In Asia, prices for November-December delivery became more bullish between late April and late July, falling back in early October, before rising to a new high in mid-October.

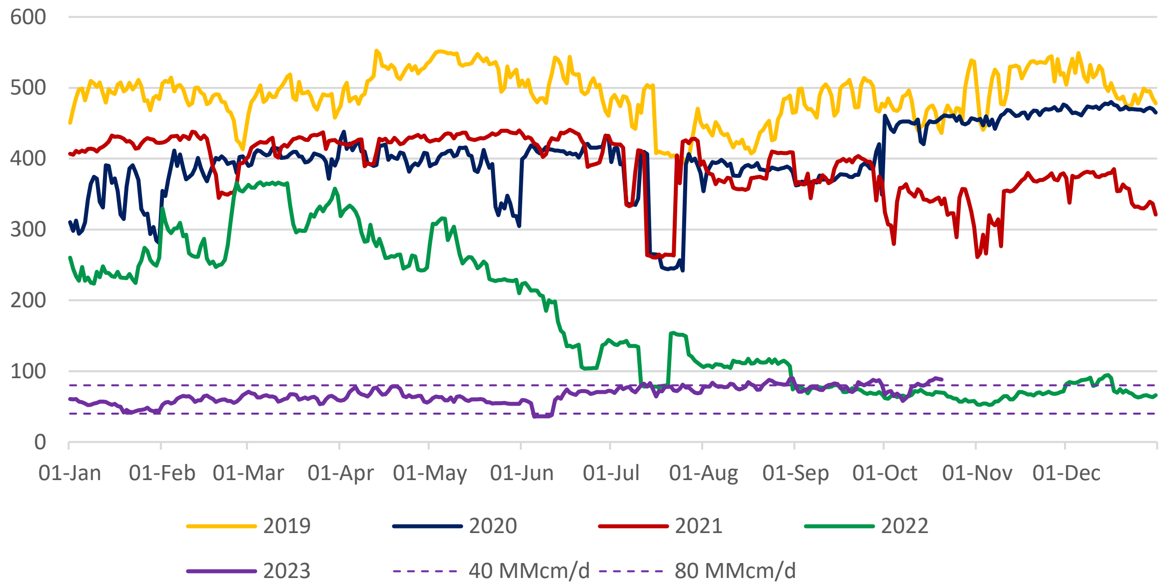
In both cases, a level of 16-17 USD/MMBtu in Europe and 17-18 USD/MMBtu in Asia are substantially lower than the front-month price levels of 37 USD/MMBtu (TTF) and 31 USD/MMBtu (ANEA) seen in October-November 2022 for delivery in November-December 2022, signifying a year-on-year improvement in the assessment of the global balance of supply-demand fundamentals. For the first half of winter, at least, the outlook appears benign relative to prices in Q4 2022, but prices are likely to remain at levels similar to those seen in Q4 2021, which were themselves historic highs.

To conclude, the forward prices illustrate a market sentiment that, while the European regional market and global LNG market are better balanced than they were 12 months ago, there is still some way to go before we can describe these markets as other than 'tight' and therefore susceptible to price volatility driven by market-moving news.

Russian pipeline supply to Europe

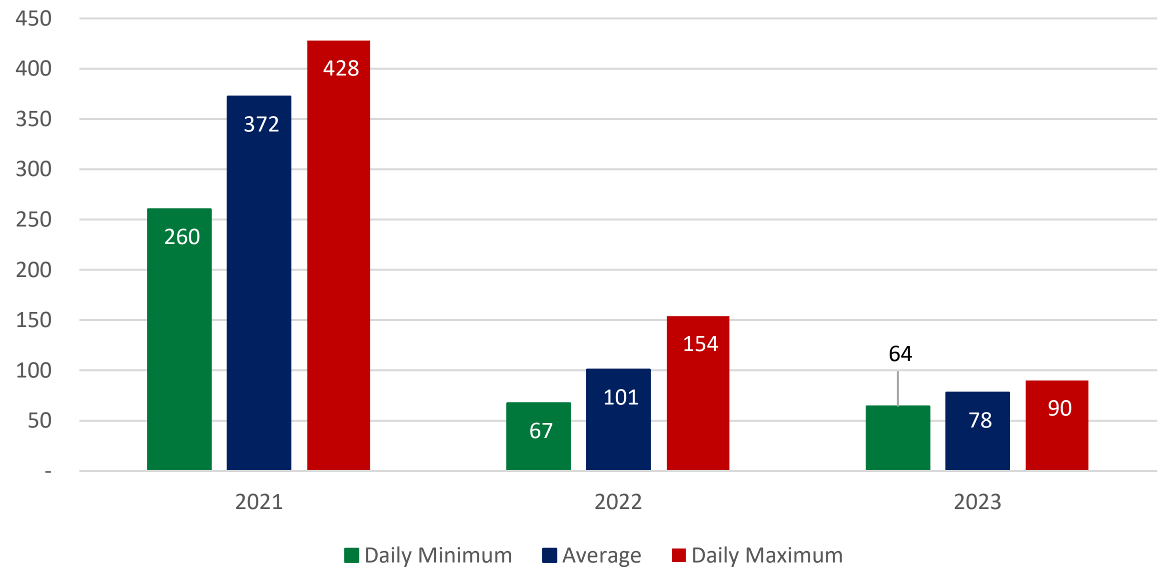
Aside from prices, the second benchmark that we to follow is the physical flow of Russian pipeline gas to Europe (excluding Turkey). In Q3-2023, this flow continued the dynamic established since 1 September 2022: Russian pipeline gas continues to flow only via Ukraine to Central Europe and via the Turkish Stream pipeline to South-East Europe.

Figure 1.4: Russian pipeline supply to Europe (MMcm/d)



Source: Data from ENTSOG.[3] Graph by the author (data to 13 October 2023)

Figure 1.5: Daily flows of Russian pipeline gas to Europe in Q3, 2021-2023 (MMcm/d)



Source: Data from ENTSOG.[4] Graph by the author

[3] ENTSOG (2023). *Transparency Platform*. https://transparency.entsog.eu/#/map
[4] ENTSOG (2023). *Transparency Platform*. https://transparency.entsog.eu/#/map

As the two graphs above illustrate, the year-on-year decline in Russian pipeline flow to Europe has narrowed through the course of 2023. This reflects the fact that the most dramatic decline in Russian pipeline supply to Europe occurred between 1 April and 1 September 2022, with the latter date marking the closure of the Nord Stream pipeline. By 1 September 2023, Russian average daily pipeline supply to Europe (excluding Turkey) was virtually unchanged year-on-year.

For more than a year now, Europe has been in a situation that could be characterised as 'a temporary new normal' regarding Russian pipeline supply, given that the Nord Stream pipeline will not be repaired any time soon, nor are the German regulatory authorities likely to authorise the start-up of Nord Stream 2 (even if that pipeline is also repaired). The Yamal-Europe pipeline, which is owned by Europol Gaz and used to deliver Russian gas to Germany via Poland, will also not return to delivering Russian gas to Europe. On 10 October, the CEO of Orlen (which merged with PGNiG in November 2022) announced that, subject to a final decision by the Polish Ministry of Development and Technology, Orlen (a 48 per cent shareholder in Europol Gaz) will take over the 48 per cent share in Europol Gaz held by Gazprom.[5]

The reason for the temporary nature of this 'new normal' is that the picture could change again at the end of 2024, with the expiry of the Russia-Ukraine gas transit contract on 31 December. As discussed in previous editions of the Quarterly Review, the 'base scenario' expectation of this author is that transit will halt upon the expiry of the contract. The fact that the current transit flows via Ukraine of around 37 MMcm/d, plus another 5-6 MMcm/d of Russian deliveries to Moldova, are far below the current ship-or-pay volume of 109.6 MMcm/d could motivate Gazprom to attempt to renegotiate the ship-or-pay volume, rather than accepting an extension of the existing contract. A Ukrainian response could be to seek a higher unit tariff to compensate for the lower ship-or-pay volume.

Any such negotiations would be complicated by the ongoing Naftogaz commercial arbitration case against Gazprom, as a result of the *force majeure* declaration by the Ukrainian TSO, TSOUA, in May 2022 and the halt of Russian gas flows into Ukraine at the Sokhranivka cross-border interconnection point, where the allocated capacity is 37.6 MMcm/d. Naftogaz claims to have offered additional capacity at the Sudzha cross-border interconnection point (where the allocated capacity is 72 MMcm/d), thus requiring Gazprom to continue paying for 109.6 MMcm/d of capacity. Gazprom however rejected that *force majeure* and has seemingly reduced its ship-or-pay payments to cover only the 72 MMcm/d of capacity allocated at Sudzha. Until it is resolved, that arbitration case could prove a barrier to any renegotiation or extension of the existing transit contract. In August 2023, the Ukrainian Energy Minister, German Galushchenko, ruled out Ukrainian participation in talks with Russian counterparties over the extension or renegotiation of the transit contract.[6]

In effect, all that is left of Gazprom's pipeline supplies to Europe are the deliveries made under long-term contracts to counterparties in Slovakia (SPP) and Austria (OMV) via Ukraine, and to Greece (DEPA, Mytilineos, and PPC), North Macedonia (MakPetrol), Serbia (Srbijagas), Bosnia & Herzegovina (Energoinvest), Croatia (PPD), and Hungary (MVM) via Turkish Stream. The situation regarding Gazprom's contracts with these counterparties was analysed in the previous Quarterly Review, and we estimate around 24.9 Bcma (ACQ) of contracts are still valid. At a flat daily delivery rate, that would imply 68.2 MMcm/d of deliveries. Given a take-or-pay range of 60-105 per cent of the ACQ, the daily delivery rate could be 41-72 MMcm/d. In addition, in August 2022, MVM signed an agreement with Gazprom for additional volumes 'up to' 5.8 MMcm/d over and above its current long-term contract. If that additional supply were fully offtaken, the Russian pipeline ACQ could be the flat-rate equivalent of 76 MMcm/d. As shown in Figure 1.5, that is close to the 78 MMcm/d daily average that was physically supplied between 1 January and 30 September 2023.

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[5] Twitter, 2023. @DanielObajtek. 10 October. https://twitter.com/DanielObajtek/status/1711786419423707601

[6] S&P Global, 2023. Ukraine rules out taking part in new Russian gas transit talks: minister. *S&P Global*, 17 August. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/081723-ukraine-rules-out-taking-part-in-new-russian-gas-transit-talks-minister

Figure 1.6: Russian pipeline supply to Europe by route (MMcm/d)

Source: Data from ENTSOG.[7] Graph by the author (data to 20 October 2023)

Deliveries via Ukraine were relatively stable at around 37 MMcm/d for much of the period since February 2023, but with more volatility in daily flows since late July. We estimate the combined contracts with Gazprom held by SPP (Slovakia) and OMV (Austria) to be 13.5 Bcm, which would imply a flat-rate of 37 MMcm/d. In addition, it has been reported that the MVM contract with Gazprom implies deliveries of 1 Bcm via Austria (i.e., via Ukraine, Slovakia, and Austria) and deliveries of 3.5 Bcma via Turkish Stream, Bulgaria, and Serbia. That additional 1 Bcma for Hungary via Ukraine/Slovakia/Austria equates to 2.7 MMcm/d. This would bring the flat-rate of Russian gas deliveries via Ukraine up to 39.7 MMcm/d. From this must be subtracted just under 1 MMcm/d, given that backhaul imports from the EU into Ukraine in the period 1 January to 30 September 2023 totalled 342.8 MMcm, according to the Ukrainian TSO, TSOUA.[8] Overall, the daily average flow of Russian gas to Europe via Ukraine is 33 MMcm/d for the period Q1-3, and the flows for much of summer 2023 align with the volumes that would have been expected on the basis of the long-term contracts in place between Gazprom and counterparties that we expect to receive their Gazprom supplies via Ukraine.

Even setting aside the scheduled maintenance of the Turkish Stream pipeline (5-11 June 2023), the flows via this route (as measured at Strandzha-2 on the Turkey-Bulgaria border) have been more volatile than the flows via Ukraine. The daily flat-rate equivalent of the ACQs of long-term contracts held by Gazprom counterparties that would expect to receive their gas via Turkish Stream total 28.5 MMcm/d (or 34.3 MMcm/d if the additional 5.8 MMcm/d to MVM in Hungary is included). For the period Q1-3 2023, the daily average flow at Strandzha-2 was 33 MMcm/d. As with the flows via Ukraine, this physical flow is similar to the volume that would have been expected based on the existing long-term contracts.

The capacity for onward delivery of gas originating via Turkish Stream gets smaller at each onward stage: at Strandzha-2 on the Turkey-Bulgaria border, the daily capacity of 572 GWh/d equates to 53.5 MMcm/d (19.5 Bcma). At Kireevo on the Bulgaria-Serbia border the 401 GWh/d of capacity equates to 37.5 MMcm/d (13.7 Bcma). Finally, at Kiskundorzsma-2 on the Serbia-Hungary border the 246 GWh/d capacity equates to 23 MMcm/d (8.4 Bcma).

[7] ENTSOG, 2023. *Transparency Platform*. https://transparency.entsog.eu/#/map

[8] TSOUA, 2023. *Transparency Platform – Page 3*. https://tsoua.com/en/transparency/test-transparency-platform/ (see the difference between physical and commercial flows for entry into Ukraine from EU member states).

As Figure 1.6 illustrates, the upper limit of the volatility in daily flows at Strandzha-2 was reached on 31 August and 28 September, when flows of 51-52 MMcm/d came close to the daily firm technical capacity. Between the launch of flows at Strandzha-2 on 1 January 2020 and 30 June 2023, daily flows exceeded 85 per cent of daily capacity just 16 times in 1,277 days. In the 92 days between 1 July and 30 September 2023, flows exceeded 85 per cent of capacity at Strandzha-2 56 times. The daily average flow in this period was 491 GWh/d (46 MMcm/d), or 86 per cent of capacity. In short, the flow of Turkish Stream gas into South-Eastern Europe intensified in Q3 2023 to levels not previously seen on a consistent basis.

Since flows at Kireevo began on 1 January 2021, they have never exceeded 313 GWh/d (29 MMcm/d), or 76 per cent of daily capacity. In Q3 2023, flows at Kireevo averaged 278 GWh/d (26 MMcm/d), or 69 per cent of capacity. However, at Kiskundorozsma-2 (launched on 1 October 2021), flows of Russian gas from Serbia to Hungary also intensified in Q3 2023, averaging 231 GWh/d (22 MMcm/d), or 94 per cent of capacity. In the 92 days of Q3, flows exceeded 85 per cent of capacity 79 times.

Overall, it appears that the uptick in flows via Turkish Stream has therefore been driven by Hungarian imports of Russian gas via its border with Serbia rising to the full capacity of that cross-border interconnection, in addition to the much smaller uptick in physical supplies from Bulgaria to Greece at Kulata/Sidirokastron. Given supply of Azeri gas and regasified LNG from Greece to Bulgaria via the Interconnector Greece-Bulgaria (IGB), the extent to which the gas supplied to the domestic Bulgarian market or re-exported to Romania is Russian or non-Russian in origin is less clear.

Given that the above analysis is based on data for flows at Strandzha-2, it is worth noting that the two main pipeline gas suppliers to the region (Russia and Azerbaijan) use different delivery routes. The flows from Turkey to Bulgaria at Strandzha-2 are dedicated to flows arriving in Turkey from Russia via Turkish Stream, which makes landfall in Turkey at Kiyikoy. The dedicated connection between Kiyikoy and Strandzha-2 is illustrated on a map published by Botaş[9] and the data for flows from Turkey to Bulgaria at Strandzha-2 (one direction only) are reported on the ENTSOG Transparency Platform by Turkstream Gas Transport A.S. (TAGTAS).[10] At Kipoi on the Turkey-Greece border, flows of Azeri gas are reported by TANAP (operator of the Trans-Anatolian Pipeline) on the Turkish side and TAP AG (Trans-Adriatic Pipeline) on the Greek side.[11] Both TANAP and TAP are pipelines dedicated to the export of Azeri gas to Turkey, Greece, and Italy. Very small, residual flows at Kipi (adjacent to Kipoi) are reported by Botaş on the Turkish side and DESFA on the Greek side, as neighbouring TSOs. Therefore, we can be sure that the flows reported at Strandzha-2 are of Russian gas supplied by Gazprom.

In the year to date (Q1-3), Russia has supplied 17,989 MMcm to the European market, down from 56,720 MMcm in Q1-3 2022, and dramatically less than the 133,131 MMcm it supplied in Q1-3 2019 (the peak year for Russian pipeline supply to Europe). If the 78 MMcm/d average in Q1-3 is maintained in Q4, Russian pipeline supply will total 25,165 MMcm in 2023, down from 63,041 (2022), and 178,852 MMcm (2019). The sheer size of the decline in Russian pipeline supply to Europe, not only year-on-year, but also relative to the pre-COVID peak, highlights the scale of the challenge Europe faced in adapting to the loss of that supply, mostly through a combination lower demand and more LNG imports. The result is a European market that could remain tight until the next large wave of LNG supply hits the global market between late 2025 and 2027, with prices remaining high enough to continue attracting LNG supply and curbing demand through a combination of increased energy efficiency consumer behaviour, and industrial fuel-switching (or demand destruction). The implication here is that the fundamentally tighter European market has less flexibility to respond to a rapid shift in the supply-demand balance, even if only relatively minor, and is therefore more likely to suffer from volatile prices.

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[9] Botaş, 2023. *Natural Gas and Crude Oil Pipeline Map*. https://www.botas.gov.tr/pages/natural-gas-and-crude-oil-pipeline-map/416

[10] ENTSOG, 2023. *Transparency Platform*. https://transparency.entsog.eu/#/map

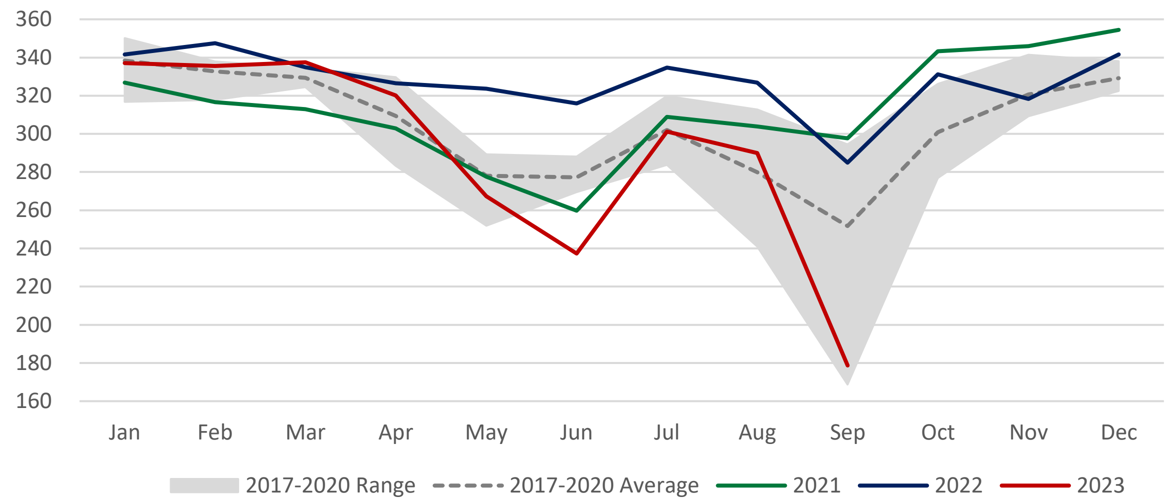
[11] Ibid.

Norwegian pipeline supply to Europe

As noted in the previous Quarterly Gas Review, Norwegian pipeline supply to Europe (or more precisely, its curtailment due to maintenance) played a significant role in the market balance of North-Western Europe in 2023 to date. While the curtailment in Q2 2023 was substantial, the curtailment in Q3 was even more so, especially in September.

In the second half of 2021, Norwegian pipeline supply to Europe responded strongly to rising prices, which were both higher than the 2017-2020 average from July onwards and higher than the 2017-2020 range from September onwards. This trend continued into 2022, where the volume delivered in summer (May to August) was significantly higher than the seasonal norm. However, by Q4 2022, flows were lower than in Q4 2021, and in February-March 2023, they were back to the 2017-2020 average. Between April and June 2023, flows fell substantially. The cause of this decline in Q2 was analysed in the previous edition of the Quarterly Review.

Figure 1.7: Monthly average Norwegian pipeline gas exports to Europe (MMcm/d)



Source: Data from ENTSOG Transparency Platform & UK Government

Moving into Q3 2023, July and August saw Norwegian daily flows recover relative to Q2, but remain around 35 MMcm/d lower than in the same months in 2022. However, the flows in September fell sharply. In the period 2017-2022, the daily average flow in September was 267-298 MMcm/d, except in 2019 when it averaged 169 MMcm/d. In 2023, the September average was 179 MMcm/d. Of course, the major difference between September 2019 and September 2023 is that the reduced flows in 2019 took place in a much looser European market, in a year of peak Russian pipeline supply and plentiful LNG from the global market, and therefore the reducing Norwegian supply did not increase prices.

It is worth noting that prior to 2022, the months of May, June, and September (when planned maintenance is conducted), were the months with the lowest Norwegian pipeline export flows. Between 2017 and 2021, monthly average flows of 260-290 MMcm/d were seen in those months, except for COVID-afflicted May 2020 (252 MMcm/d), and September 2019 (169 MMcm/d). Therefore, the September 2023 flow of 179 MMcm/d was substantially lower than normal, even when considering that September is traditionally a 'low month' for Norwegian pipeline supply to Europe.

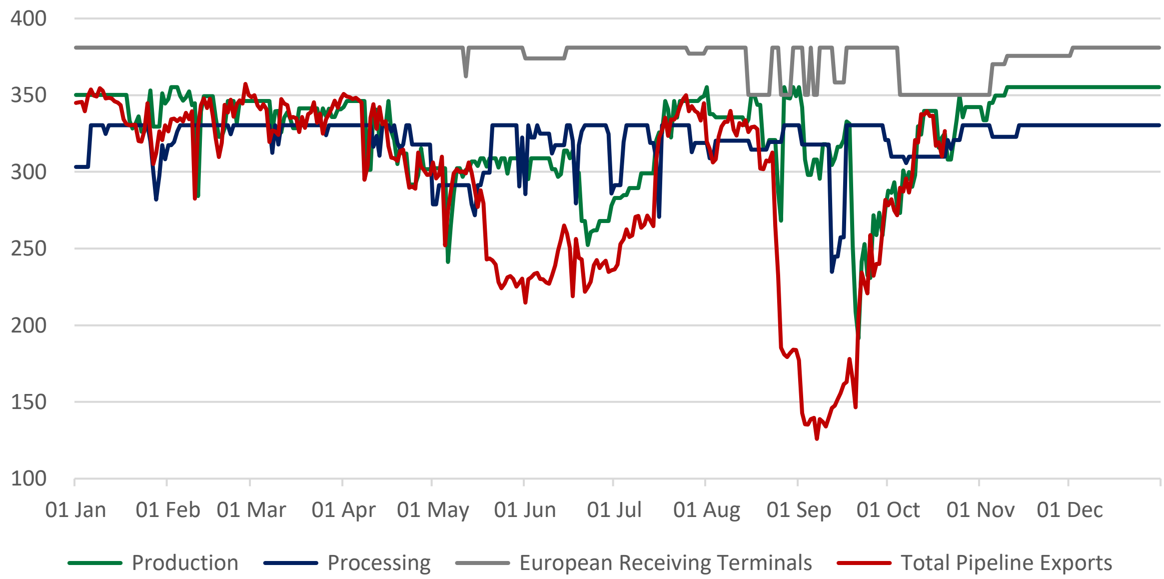
Flows in July, August, and October were between the winter highs of November-April and the summer maintenance lows. In July and August between 2017 and 2023, supply was generally 277-320 MMcm/d, except for the lows of August 2019 (241 MMcm/d) and August 2020 (262 MMcm/d), and the price-driven highs of July-August 2022 (335 and 327 MMcm/d) and October 2021 (343 MMcm/d). This means that the flows in July-August 2023 (301 and 290 MMcm/d) were within the 'normal' range, albeit lower year-on-year and lower than the July-August flows seen in the tighter markets of 2017, 2018, and 2021.

Since January 2017, the monthly average flows between November and April have been higher than 303 MMcm/d (85 per cent of 356 MMcm/d production capacity) in every month except the COVID-afflicted April 2020. The record monthly average Norwegian pipeline delivery (354 MMcm/d) occurred in December 2021. Therefore, winter months have seen Norwegian pipeline deliveries of 303-354 MMcm/d from November to April every winter since 2017, and usually in the range of 330-345 MMcm/d. Norwegian daily supply on 10 October (321 MMcm/d) surpassed 300 MMcm/d for the first time since 23 August, reaching 340 MMcm/d on 14 October before falling back to 327 MMcm/d on 20 October, thus placing flows firmly back within the 'normal' winter range.

As in May-June, the September decline in Norwegian flows may be attributed to maintenance work that curtailed three key elements of Norwegian supply: field production capacity; processing plant capacity; and European receiving terminal capacity. As a baseline point of comparison, Norwegian production capacity (excluding gas produced at the Snøhvit field for export via the Hammerfest LNG plant) is estimated at 356 MMcm/d. The combined processing capacity at Nyhamna, Kollsnes, and Kårstø is estimated to be 330 MMcm/d. In addition, some Norwegian gas is delivered directly from the Norwegian Continental Shelf for processing at St Fergus (UK), where the receiving capacity is 30 MMcm/d. The European terminals receiving Norwegian pipeline supply have an estimated combined capacity of 381 MMcm/d, including 30 MMcm/d at Nybro (the beginning of the Baltic Pipe to Denmark and Poland, launched on 1 November 2022).

Overall, therefore, total Norwegian supply capacity of 356 MMcm/d appears to be a logical total, based on production capacity being similar to the processing capacity inclusive of St Fergus, and pipeline transportation capacity in excess of the production and processing capacity. In the 81 months between January 2017 and September 2023, monthly average Norwegian pipeline exports exceeded 345 MMcm/d (97 per cent of the estimated 356 MMcm/d capacity) just four times, and exceeded 350 MMcm/d just twice. In other words, a monthly average pipeline supply from Norway above 345 MMcm/d is 'high' and monthly average supply above 350 MMcm/d is 'exceptionally high'.

Figure 1.8: Norwegian daily production, processing, and export receiving terminal capacity after maintenance curtailments as reported by Gassco (MMcm/d)

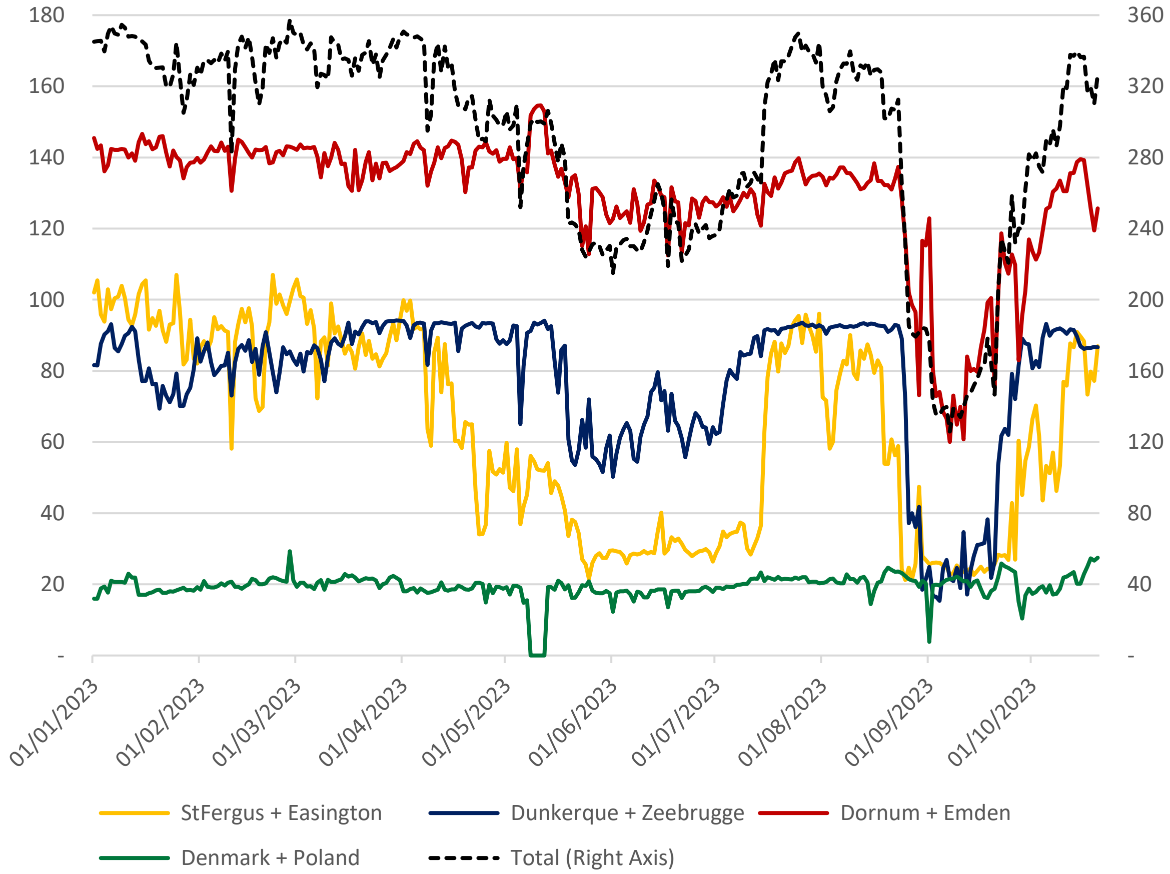


Source: Gassco, graph by the author[12]

[12] Gassco, 2023. *Gassco Urgent Market Messages (UMM)*, 22 October. https://umm.gassco.no/

In this context, the curtailments in production, processing, and export capacity reported by Gassco were the cause of lower Norwegian supply in summer 2023, and in September in particular. Figure 1.8 illustrates the sharp decline in production and processing capacity between mid-April and late May, the recovery in July-August, and the decline again in September. The impact on the physical flows to each of the European terminals that receive Norwegian pipeline supply is illustrated in Figure 1.9 (below).

Figure 1.9: Daily Norwegian pipeline gas exports to Europe since 1 January 2023 (MMcm/d)



Source: Data from ENTSOG Transparency Platform & UK Government (data to 13 October 2023)

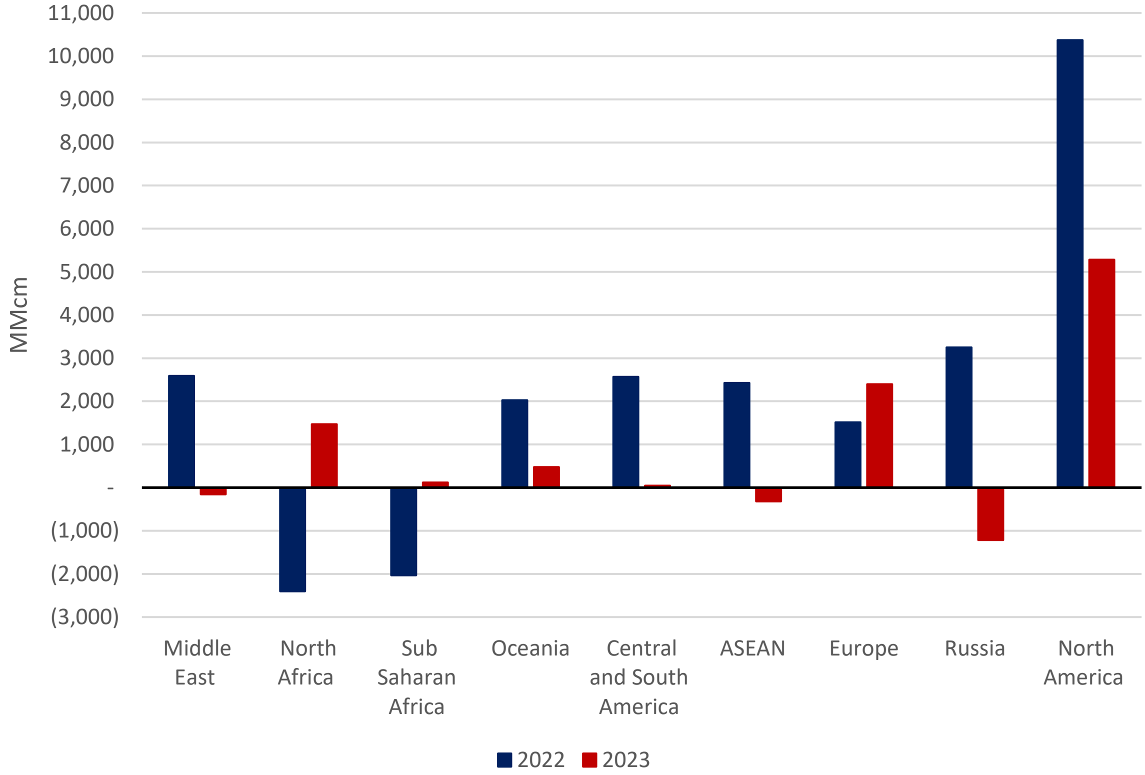
Looking ahead into Q4 2023, Norwegian capacity to supply pipeline gas to the European market is set to return close to 'normal' from 21 October, with production capacity (280-300 MMcm/d in early October) set to return to 345 MMcm/d, while processing capacity (310 MMcm/d in early October) is set to return above 323 MMcm/d, and the capacity of terminals receiving Norwegian pipeline supply (350 MMcm/d in early October) is set to return to 365 MMcm/d.

The return of Norwegian supply to 'normal' levels in late October will be welcomed, given the expected start of winter seasonal demand and the market jitters generated by events in the Baltic Sea and Middle East, and the potential impact of industrial action on Australian LNG supply. Indeed, robust Norwegian pipeline supply will be a crucial factor if Europe is to limit its storage drawdown in winter 2023/24, and thus limit the extent of storage stock replenishment necessary in summer 2024.

Global LNG supply

According to data from Kpler, global LNG supply[13] grew from 478.7 Bcm in 2020 to 503.7 Bcm in 2021 and 530.4 Bcm in 2022, meaning that year-on-year growth rates of approximately 4-5 per cent were seen in 2021 and 2022. In the first nine months of 2023, gross global LNG supply grew by 8.1 Bcm (2.05 per cent), which was notably lower than the year-on-year growth seen in the first nine months of 2021 (16.4 Bcm, or 4.6 per cent), and 2022 (20.3 Bcm, or 5.4 per cent).

Figure 1.10: Year-on-year change in global LNG supply by source in Q1-3 2022 and Q1-3 2023 (MMcm)



Source: Data from Kpler.[14] Graph by the author

In geographical terms, the growth in supply from the United States has resumed, in particular due to increased supply from Freeport LNG, which did not load any cargoes between 7 June 2022 and 12 February 2023, having been closed due to a fire. Prior to the shutdown, Freeport had seen loadings in excess of 1.63 Bcm (1.2 million tonnes) per month in 7 of the 11 months prior to June 2022, but did not return to that level until May 2023, having ramped up steadily from 0.816 Bcm (0.6 mt) in March and 1.55 Bcm (1.14 mt) in April. Elsewhere in the United States, there has also been a ramp-up of supply from Calcasieu Pass, which launched in March 2022, and supplied 5.3 Bcm (3.9 mt) in Q1-3 2022 and 9.25 Bcm (6.8 mt) in Q1-3 2023.

[13] Some countries are simultaneously exporters and importers of LNG, such as Egypt, Indonesia, Malaysia, Norway, UAE, and the United States. Therefore, we use a net figure for all countries except the six listed here. Therefore, this figure includes only supply from export plants and does not include re-exports from import terminals (for example, in Belgium, France, and Spain).

[14] Kpler, 2023. *LNG Platform*. https://lng.kpler.com/ [subscription required]

Elsewhere, the other notable year-on-year addition to supply in the first nine months of 2023 was from Europe, specifically from the Snøhvit LNG liquefaction plant in Hammerfest. Having been shut down by a fire in September 2020, the plant returned to operation in June 2022. Therefore, having contributed zero supply in most of H1 2022, it returned to full capacity for much of this year, although it was taken offline again by compressor failure for several weeks in May and process problems for two weeks in June.[15] The nameplate export capacity of 4.2 mtpa (5.7 Bcma) at Hammerfest implies a monthly average export of 0.35 mt. Here it is worth noting that Hammerfest LNG can produce substantially above its nameplate capacity, with monthly exports of 0.43-0.46 mt per month on 13 occasions since August 2018 (23-31 per cent above nameplate capacity). Of those months with production well above nameplate capacity, eight occurred before the fire in September 2020, four occurred between September 2022 and March 2023, and once again in September 2023. This implies a high rate of utilisation in winter 2022/23, and a possible repeat in winter 2023/24.

North Africa has also seen rising LNG exports of some 1.5 Bcm in the first nine months of 2023 as Algeria diverts flows to LNG as opposed to pipeline gas to Europe. On the negative side, exports from Nigeria and Egypt are down because of feedgas issues. Extended maintenance at the Sakhalin-II LNG export plant in Russia was announced in late April, scheduled to begin on 1 July. In the event, Sakhalin-II weekly exports were notably below usual levels from the last week in June to the first week in August.[16]

In the January Quarterly Review, it was noted that there were not many brand-new projects coming on in 2023, but despite that, another robust year for supply growth was expected. The only new start-ups were expected to be in Congo, Senegal/Mauritania (Tortue) and in Indonesia (Tangguh Train 3). The first two seem likely to start production towards the end of the year, or early next year, while BP loaded its first cargo from Tangguh Train 3 on 19 October. Overall, LNG export capacity was projected to rise by around 29 Bcm in 2023, with some 13 Bcm coming from the ramping up of plants that came on in 2022 – Sabine Pass Train 6, Calcasieu Pass, Coral FLNG (Mozambique) and Portovaya (Russia). An additional 6 Bcm could also come from Freeport resuming production and reaching full output in Q2. A full year of production can also be expected from Norway and fewer feedgas issues in Trinidad (where output is already ramping higher) and Nigeria.

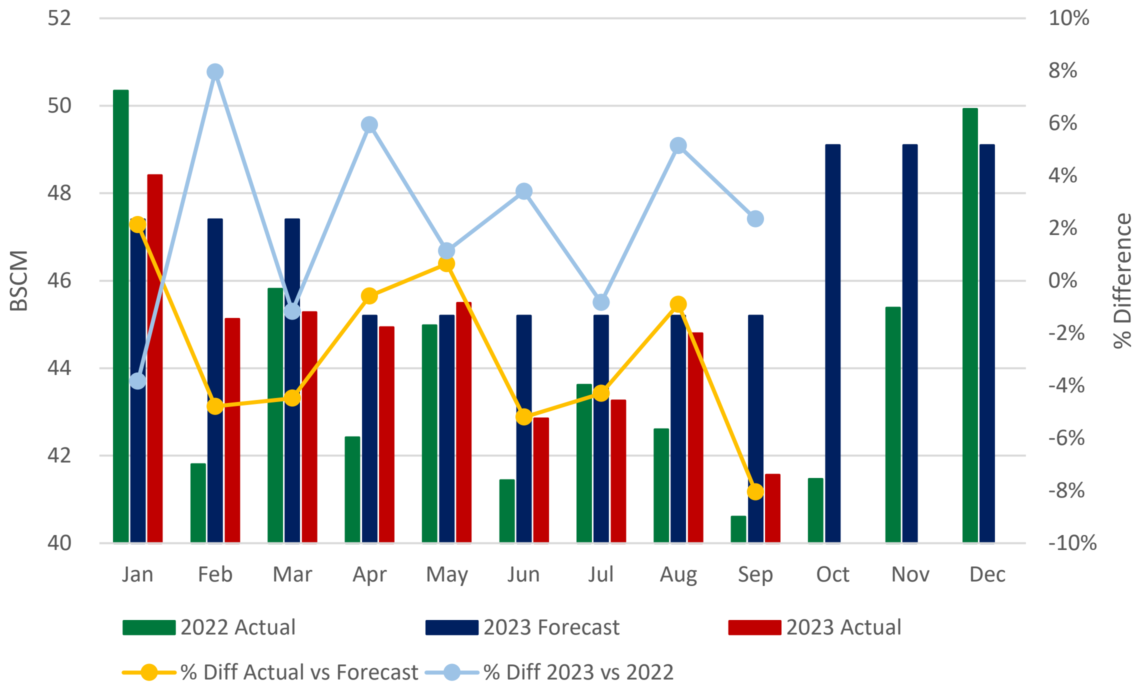
On that basis, in the January Quarterly Review we forecast that global LNG supply could be 1.4 Bcm per month higher year-on-year in Q1, 2.2 Bcm per month higher in Q2, 2.8 Bcm per month higher in Q3, and 3.8 Bcm per month higher in Q4. Fulfilling that forecast would result in global LNG supply of 47.4 Bcm per month in Q1 2023, 45.2 Bcm per month in Q2 and Q3, and 49.1 Bcm per month in Q4.

As we have progressed through 2023, there have been some changes to the supply outlook, with extended maintenance planned for the Sakhalin project in Russia, continuing issues with a train in Malaysia, a lack of recovery in feedgas in Nigeria, and a further shutdown for Prelude. This has reduced the likely growth in LNG export capacity to some 19 Bcm in 2023. In the figures below we compare the monthly actual growth in LNG supply against our initial forecast for 2023 and also against 2022 supply. Here it is notable that actual supply was well below our start-of-year forecast in every month except January, April, and May, but higher year-on-year in every month except January and July. Therefore, generally speaking, LNG supply has been growing year-on-year, but more slowly than forecast back at the start of the year.

[15] Gassco, 2023. Urgent Market Messages (UMM). *Gassco*, 22 October. https://umm.gassco.no/

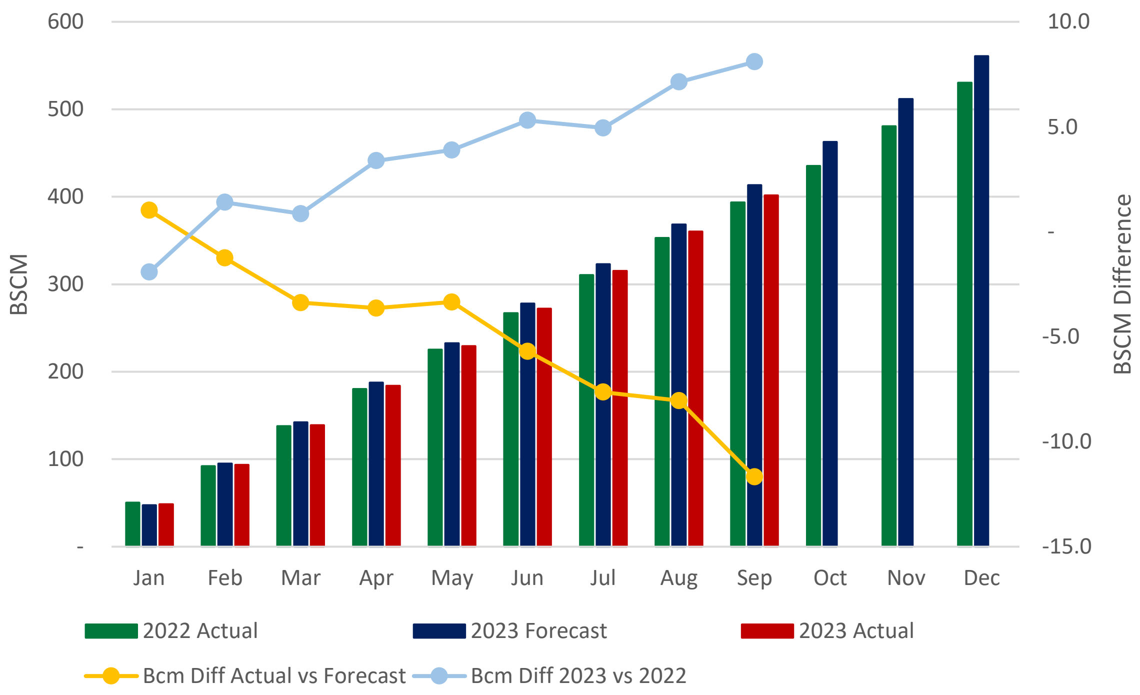
[16] Kpler, 2023. *LNG Platform*. https://lng.kpler.com/ [subscription required]

Figure 1.11: Average monthly global LNG supply (Bcm per month)



Source: NexantECA World Gas Model, OIES Estimates, Kpler

Figure 1.12: Cumulative monthly LNG supply (Bcm per month)



Source: NexantECA World Gas Model, OIES Estimates, Kpler

The cumulative monthly global LNG supply in the first nine months of 2023 was 8.1 Bcm (2.05 per cent) higher than in 2022 but below our start-of-year forecast by 3.4 Bcm (1.3 per cent). Output from Sub-Saharan Africa (mainly Nigeria), the United States, and the UAE have been somewhat lower than anticipated and Russia has also been lower.

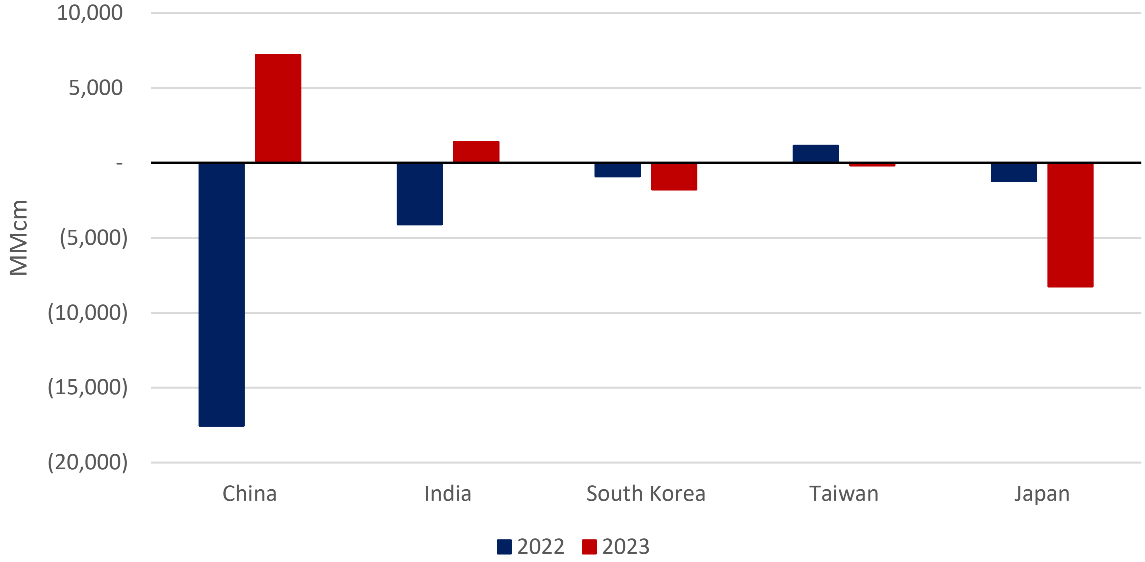
However, it should be noted that LNG supply is measured as the cargoes arrive at the importing terminals – the imports basis from Kpler. If supply was measured as the volumes leaving the exporting terminals – the exports basis – then the measured growth in supply would be much bigger. The increase in cumulative monthly supply (exports basis) in the first nine months of 2023 was some 13 Bcm, compared to a measured rise of 8.1 Bcm (imports basis). Depending on the destination of the LNG exports, the voyage time can be anything from a few days or a week to between 4 and 6 weeks. LNG leaving an exporting terminal, therefore, could easily take a month to arrive at the importing terminal, which is what we are measuring here. Eventually the growth in the export-basis measure of supply and the import-basis measure of supply should match. This will either be achieved by the import-basis measure increasing to meet the export-basis measure or a much slower growth in exports over the next few months.

Asian LNG demand

The January Quarterly Review noted that what happens to Asian LNG demand is key in the development of the global LNG market. 2022 was the first year that total Asian LNG imports declined. Chinese LNG imports were only just above 2019 levels, losing almost two years of growth. India's imports were back to 2017 levels and Pakistan's LNG imports fell back to 2018 levels. In China, flat domestic demand combined with rising indigenous natural gas production and pipeline imports to curb LNG demand. India, Pakistan, and Bangladesh also saw declines as demand was hit by rising prices and, in some cases, sellers opting not to deliver under contracts. Japanese LNG demand continued its downward trend of the last 5 years or so – LNG imports are now lower than before the 2011 Fukushima incident. There were some growth areas though, especially the South-East Asian countries, which were less exposed to the very high spot prices thanks to the prevalence of oil-indexed long-term contract supply.

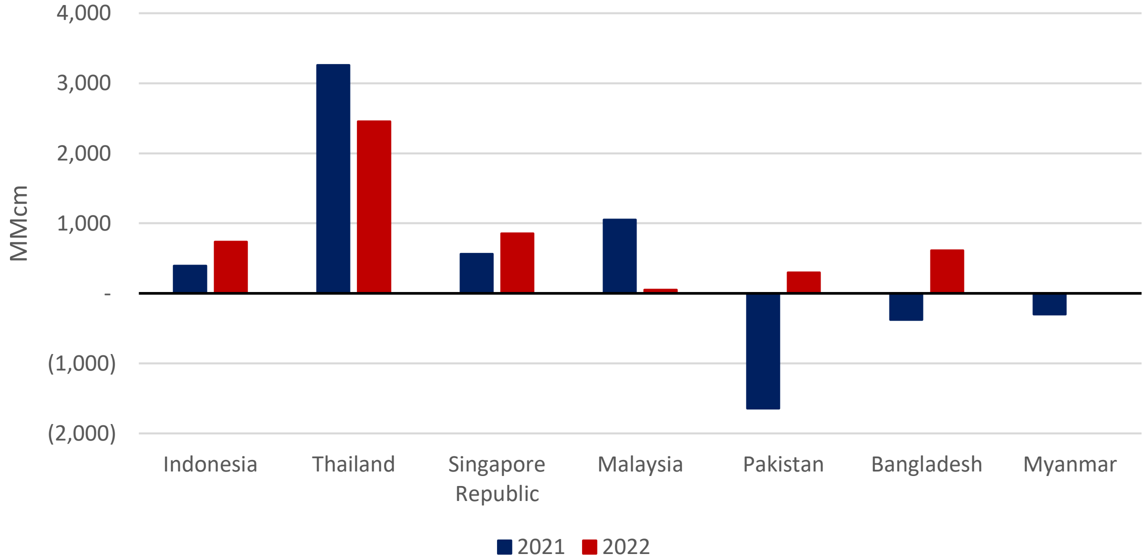
In 2023, China finally returned to modest growth in May and June, and has grown much more strongly in Q3. India has recently been stronger, as have Pakistan and Bangladesh, but Japan especially has seen much lower demand with a weak economy and higher nuclear output. The consistently strong growth areas have been in South-East Asia, with the Philippines and Vietnam joining the importers club.

Figure 1.13: Year-on-year change in Asian LNG demand (major importers) in year-to-date (Q1-3) 2022 and 2023



Source: Data from Kpler. [17] Graph by the author

Figure 1.14: Year-on-year change in Asian LNG demand (smaller importers) in year-to-date (Q1-3) 2022 and 2023



Source: Data from Kpler. [18] Graph by the author[19]

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[17] Kpler, 2023. *LNG Platform*. https://lng.kpler.com/ [subscription required]

[18] Kpler, 2023. *LNG Platform*. https://lng.kpler.com/ [subscription required]

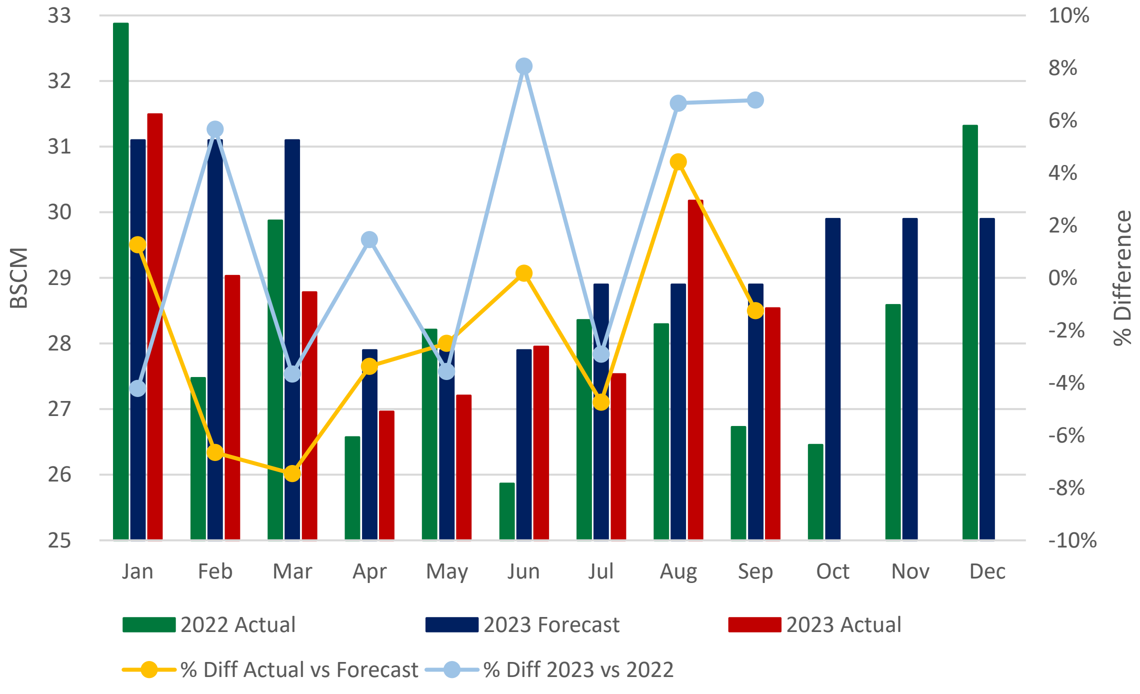
[19] Note that Indonesia and Malaysia are net LNG exporters, but still import LNG

In the January Quarterly Review, Asian LNG imports were projected to grow by some 1 Bcm per month (12 Bcm in total over the course of 2023), driven in part by China growing again. With China failing to recover in the early part of the year, total LNG imports were not only below target but also below 2022 levels as it wasn't until June that cumulative volumes rose above 2022 levels. With China growing much stronger and ASEAN and recently South Asia also growing, it was only Japan and Korea holding growth back. By September, cumulative Asian LNG imports were 3.4 Bcm above 2022 levels but 6.0 Bcm below the cumulative target.

Overall, the fact that global LNG supply in the nine months of 2023 grew by 2.05 per cent (8.1 Bcm) year-on-year while Asian LNG demand grew by 1.35 per cent (3.4 Bcm) year-on-year, combined with little or no growth in LNG imports elsewhere, provided the additional supply that enabled European[20] LNG imports (cargo offloads) in the first nine months of 2023 to grow by 3.05 Bcm (2.8 per cent) year-on-year. Sendout from European LNG regasification terminals was up by 3.4 Bcm (3.3 per cent) year-on-year, reflecting the higher imports (cargo offloads).

In the context of pipeline supply from North Africa and Azerbaijan that was relatively flat year-on-year (declining by a combined 0.4 Bcm), Norwegian pipeline supply that was 10.1 Bcm (11.3 per cent) lower, and Russian pipeline supply that was 38.7 Bcm (68 per cent) lower year-on-year, the combination of lower overall gas demand (-31.4 Bcm)[21] and higher LNG imports (+3.7 Bcm) provided the fundamentals that underpinned the substantial decline in European prices between January and June. At the same time, the combination of growing supply and weak Asian LNG demand underpinned the parallel decline in JKM prices in the same period.

Figure 1.15: Average monthly Asian LNG demand (Bcm per month)

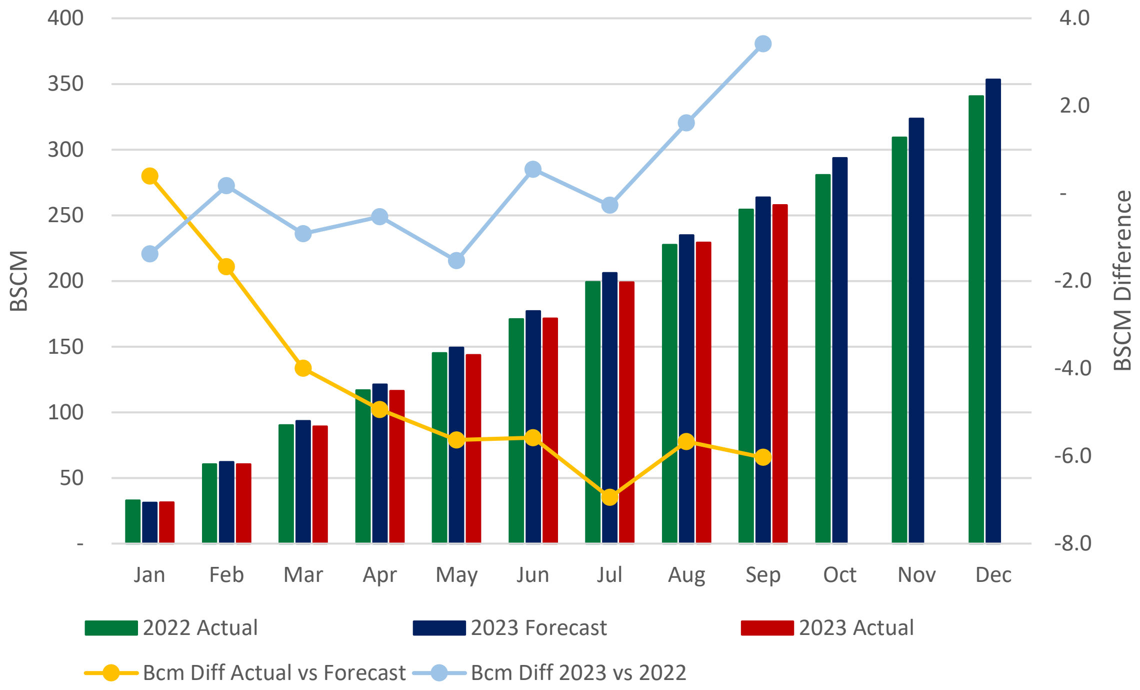


Source: NexantECA World Gas Model, OIES Estimates, Kpler

[20] EU-27 plus the UK

[21] Note this figure does not account for physical re-exports from Europe to Ukraine in Q1-3, which rose by 2.75 Bcm year-on-year. When re-exports to Ukraine are accounted for, European supply (implied consumption) fell by 34.1 Bcm (11.3 per cent) year-on-year

Figure 1.16: Cumulative monthly Asian LNG demand (Bcm per month)



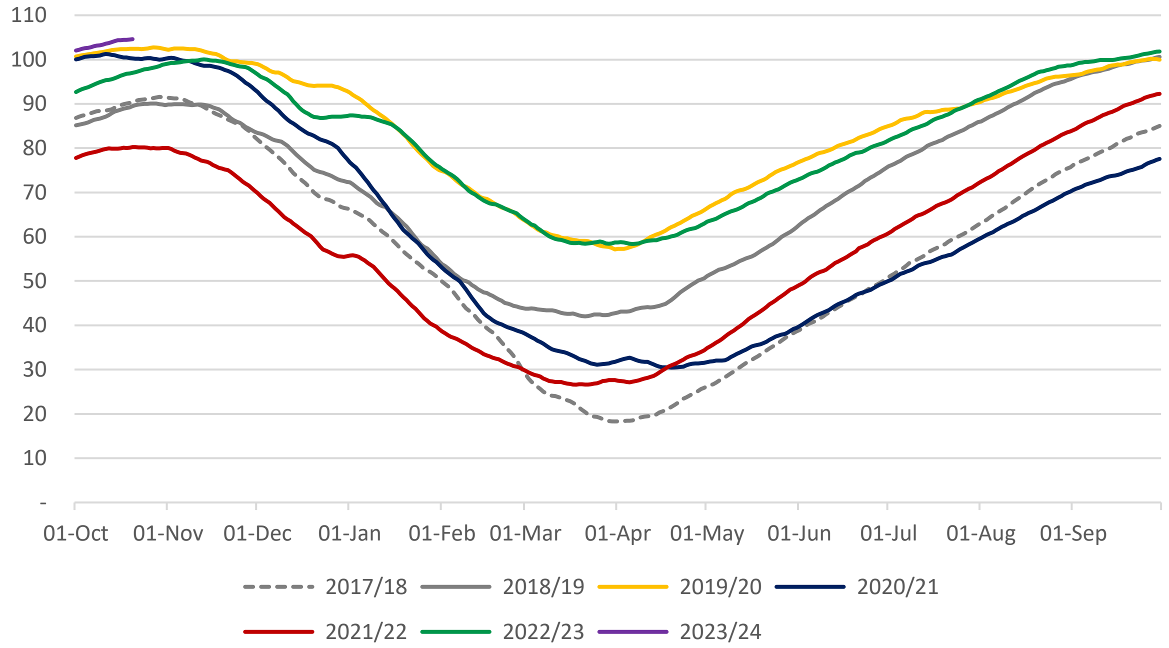
Source: NexantECA World Gas Model, OIES Estimates, Kpler

European gas storage

Europe began Q3 with storage stocks of 81.8 Bcm on 1 July, which were 20.9 Bcm higher year-on-year, slightly below the previous record for that date (85.0 Bcm on 1 July 2020), and far higher than on 1 July in 2018, 2019, 2021, and 2022, as illustrated in the graph below.

Europe ended Q3 2023 with 102.0 Bcm in storage on 1 October, which was 9.4 Bcm higher than on 1 October 2022 and slightly higher than the previous records for that date (100.7 Bcm on 1 October 2019 and 100.0 Bcm on 1 October 2020).

Figure 1.17: European gas storage stocks (Bcm)



Source: Data from Gas Infrastructure Europe (GIE) Aggregated Gas Storage Inventory.[22] Graph by the author

Throughout summer 2023, the European Commission had intermediate targets for storage refill and an overall target of filling storage to 90 per cent of capacity (94.2 Bcm) by 1 November 2023.[23] Stocks on 1 July 2023 (81.8 Bcm) surpassed the Commission target for 1 July by 33.4 Bcm, and stocks on 1 September (98.8) not only surpassed the 76.6 Bcm target for that date, but also the overall target for 1 November.

However, the achievement of the storage filling targets was based on a very favourable starting position on 1 April 2023, with stocks at a record 58.7 Bcm slightly higher than the previous record of 57.2 Bcm (1 April 2020) and far higher than stocks on that date in any previous year. Conversely, net storage injection in Q3, and in the summer as a whole (Q2-3), was modest compared to previous years.

In Q3, Europe made a net injection of 20.3 Bcm. In the ten previous years, from 2013 to 2022, European Q3 net storage injections ranged from 28 to 34 Bcm in seven of those ten years. The net injection in Q3 2023 was very similar to that made in Q3 2014 (20 Bcm), lower than in Q3 2019 (25 Bcm) and higher than the net injection made in Q3 2020 (15 Bcm).

[22] GIE, 2023. *Aggregated Gas Storage Inventory*. https://agsi.gie.eu/data-overview/eu

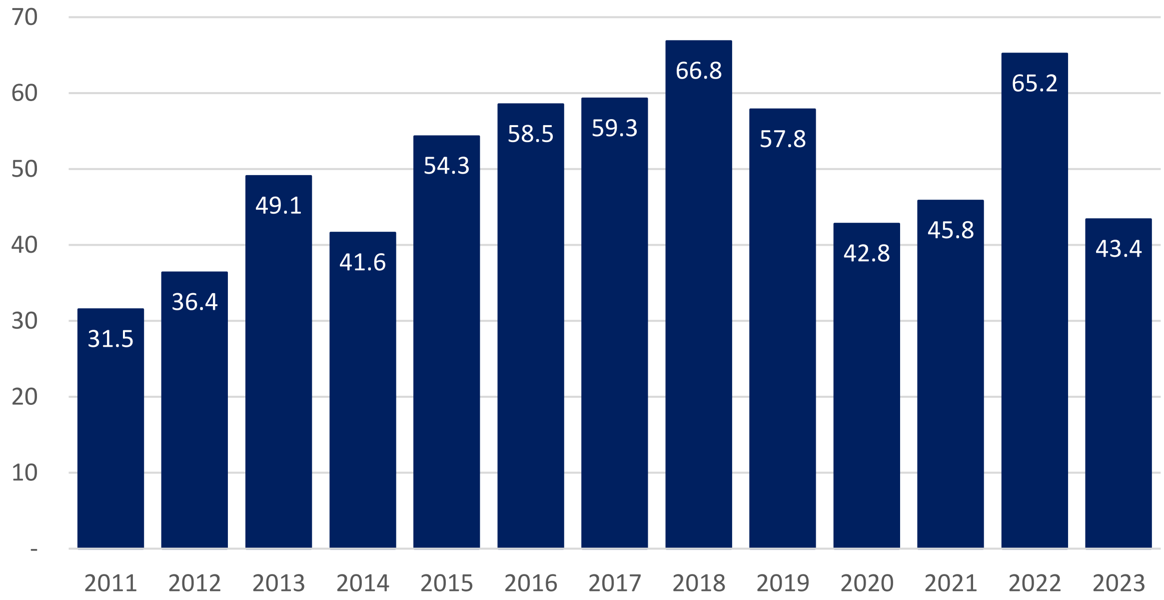
[23] European Commission, 2022. Commission sets trajectories for filling gas storage in 2023. *Press Release*, 24 November. https://commission.europa.eu/news/commission-sets-trajectories-filling-gas-storage-2023-2022-11-24-0_en

In the summer (Q2 and Q3 combined), the net injection of 43.3 Bcm was more than 20 Bcm lower than the net injection made in summer 2022. As Figure 1.18 shows, one would need to go back to 2012 to find a net summer injection that was notably lower than the net injection made in summer 2023. EU storage capacity reached its present level in 2016, so lower stocks would be expected prior to that.

The stockbuild in summer 2023 was achieved despite significantly lower year-on-year Russian pipeline supply (especially given that Nord Stream was still fully operational in April and May 2022), and Norwegian supply curtailed by maintenance. This lower pipeline supply was expected, while LNG imports had already risen substantially by summer 2022, leaving only limited scope for further increases in 2023. Indeed, European LNG sendout from regasification terminals in Q2-3 rose from 38,246 MMcm in 2021 to 67,991 MMcm in 2022, before falling very slightly to 67,747 MMcm in Q2-3 2023.

In effect, the year-on-year decline in net storage injections (-21.2 Bcm) and implied consumption (-11.7 Bcm) in Q2-3 2023 – a total of 32.9 Bcm – offset the reductions in supplies. These were the 17.7 Bcm year-on-year decline in Russian pipeline supply; the 9.7 Bcm year-on-year decline in Norwegian pipeline supply; and the 5.6 Bcm year-on-year decline in European production. A small increase in pipeline supply from North Africa (+0.5 Bcm) was only just enough to offset the slight declines in LNG sendout (-0.25 Bcm) and in pipeline supply from Azerbaijan (-0.15 Bcm).

Figure 1.18: European net storage injections 1 April to 1 October (Bcm)



Source: Data from Gas Infrastructure Europe (GIE) Aggregated Gas Storage Inventory.[24] Graph by the author

Looking ahead, while Norwegian pipeline supply may be higher year-on-year in summer 2024 (due to less maintenance), it is not expected that EU+UK production or pipeline supply from any other supplier will be higher, while the potential for a year-on-year increase in LNG imports remains uncertain. Therefore, while a partial rebound in Norwegian supply to 'normal' summer levels and a modest year-on-year decline in summer demand could enable storage refill in summer 2024 to rise to around 50 Bcm (from 43 Bcm in 2023), a return to summer refills closer to 58-65 Bcm seen in 2016-19 and again in 2022 would not be possible without another substantial rise in LNG imports, which would need to be attracted by higher prices. The implication is that if Europe is to begin winter 2024/25 with storage once again full by 1 October, it requires a combination of robust supply and an absence of cold winter demand levels to limit storage withdrawals in winter 2023/24.

[24] GIE, 2023. *Aggregated Gas Storage Inventory*. https://agsi.gie.eu/data-overview/eu

Ukrainian gas storage: where are we now?

In the previous issue of the Quarterly Review, we noted the potential for gas storage facilities in western Ukraine to be used to absorb additional volumes, as facilities in the EU reach full capacity. As a reminder, Ukraine has 322 TWh (31 Bcm) of gas storage capacity,[25] of which 17 Bcm is at the Bilche-Volytsko-Uherske facility in western Ukraine, close to the city of Lviv and Ukraine's border with Slovakia.[26]

Ukraine already has a scheme in place for European companies to store gas in Ukraine. Since April 2019, under the 'Customs Warehouse' scheme, European companies may import gas into Ukraine without paying customs duties, and store it for up to three years. At any point up to that three-year limit, they may either withdraw the gas from storage and re-export it without paying any customs duties, or they may pay the customs duty and sell the gas into the Ukrainian market. Since January 2020, TSOUA (the Ukrainian TSO) has offered discounted entry-exit tariffs for gas being transported between the Ukrainian border and Ukrainian gas storage facilities, and discounted transportation tariffs for the transport of gas from one EU member state to another – for example, from Poland to Hungary - via western Ukraine (the so-called 'short haul' tariffs).

Gas Infrastructure Europe reports that Ukraine held 124.7 TWh (11.67 Bcm) in storage on 20 October 2023, up from 102.3 TWh (9.57 Bcm) on 20 October 2022. Ukraine's summer seasonal storage injections began on 15 April, when stocks stood at 48.17 TWh (4.51 Bcm). By 1 May, stocks stood at 50.00 TWh (4.68 Bcm). Therefore, seasonal injections between 1 May and 20 October totalled 74.7 TWh (6.99 Bcm).[27] During that same period, Ukraine's gas imports from EU member states totalled 3,061 MMcm, of which 2,683 MMcm was a physical flow and the remaining 379 MMcm was a 'commercial flow' obtained via backhaul (otherwise known as 'virtual reverse'). Of these imports, 2,553 MMcm were destined for the Customs Warehouse.

Imports conducted under the Customs Warehouse regime rose from 88 MMcm in May-June to 444 MMcm in July and 926 MMcm in August, before falling back to 861 MMcm in September and 235 MMcm in 1-20 October.[28] For comparison, in 2022, Ukraine saw imports of just 235 MMcm between April and September under the Customs Warehouse regime, plus a further 262 MMcm in October and 191 MMcm in November. That trend in 2022 could reflect the fact that storage facilities in the EU were still only 89 per cent full on 1 October, meaning that there was not a pressing need to use Ukrainian storage for injections in late summer, leading to the Customs Warehouse imports in October 2022 alone being higher than in the whole of Q2-3 2022. By contrast, Ukraine's Customs Warehouse imports between 1 May and 20 October 2023 were around 10 times higher than in 2022, with 2,236 MMcm being imported to the Customs Warehouse in 'late summer' between 1 July and 1 October.

Looking ahead to the rest of Q4, it is worth remembering that a mild start to winter in 2022 enabled storage injections in the EU-27 to continue to 15 November. With EU-27 storage 98.2 per cent full on 20 October 2023, with stocks of 104.6 Bcm (1,119 TWh) and storage capacity of 106.45 Bcm (1,138 TWh), another month of storage injections would require injections into Ukraine's gas storage facilities.

Finally, it is worth noting that not all the gas imported into Ukraine and injected into storage under the Customs Warehouse regime is destined for re-export back to the EU. As an alternative, the holder of those stocks can choose to pay the customs duty and sell the gas into the Ukrainian market. Whether or not this happens depends on the differentials between prices in Ukraine and the EU, and the entry-exit tariffs levied on the Ukrainian and EU sides of the border.

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[25] AGSI, 2023. *Gas Infrastructure Europe Aggregated Gas Storage Inventory – Ukraine*. https://agsi.gie.eu/data-overview/UA

[26] UkrTransGaz, 2023. *We Store Energy for Your Safety*. February 2023. https://utg.ua/en/img/menu/company/docs/2023/eng_16-02.pdf (see pages 12-13)

[27] AGSI, 2023. *Gas Infrastructure Europe Aggregated Gas Storage Inventory – Ukraine*. https://agsi.gie.eu/data-overview/UA

[28] TSOUA, 2023. *Transparency Platform (see pages 3-4)*. https://tsoua.com/en/transparency/test-transparency-platform/

Total supply to Europe (implied consumption)

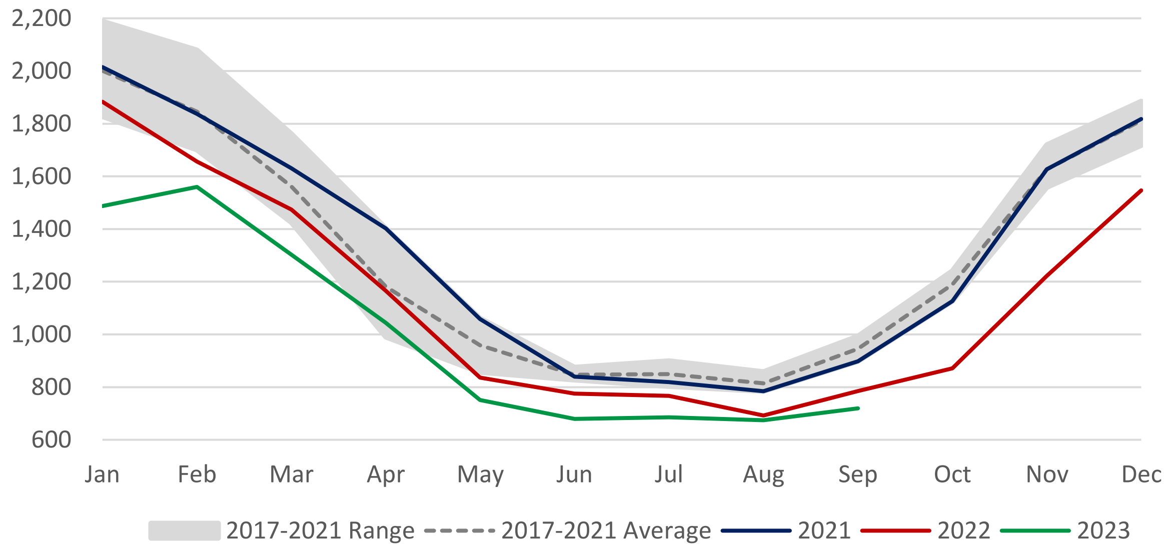
By gathering together data for European production, pipeline imports, LNG imports, and net storage withdrawals, it is possible to calculate Europe's 'implied gas consumption'. This overall total supply (implied consumption) is presented in Figure 1.19 below.

It is perhaps to be expected that, following the substantial year-on-year decline in European gas consumption in every month in 2022, the subsequent year-on-year decline in 2023 should be somewhat smaller, with many of the 'low hanging fruit' (in terms of energy efficiency and fuel-switching) having already been picked. The seasonal pattern of demand also matters, with the difference between a cold and a mild winter being substantial in terms of gas demand, while the difference between a cool and a hot summer (in terms of gas demand for power generation led by air conditioning load) being rather less substantial.

In January-September 2023, total European supply fell from 304.1 Bcm to 272.3 Bcm (-31.8 Bcm, or -10.5 per cent). When the increase in physical re-exports from Europe to Ukraine is included, implied European consumption fell from 303.3 Bcm to 268.8 Bcm (-34.5 Bcm, or -11.4 per cent).

The year-on-year decline in implied gas consumption reached its smallest in August 2023, with implied consumption of 674 MMcm/d compared to 692 MMcm/d in August 2022 (-2.6 per cent). The differential widened in September 2023 to -8.3 per cent year-on-year. While demand remained lower year-on-year through most of the first half of October, colder weather in the second half of October could push the October daily average demand higher for the month as a whole. What happens thereafter will be substantially influenced by seasonal temperatures and consumer behaviour.

Figure 1.19: Total supply to Europe[29] (MMcm/d)



Source: Data from ENTSOG[30], Eurostat[31], Kpler[32], and Gas Infrastructure Europe[33]. Graph by the author

[29] Europe is defined as the EU, UK, Switzerland, and non-EU Balkan states. It excludes Turkey and treats Norway as an external supplier to that European market. Note that 'Total Supply' refers to production plus pipeline imports plus LNG sendout plus net storage withdrawals. Physical re-exports to Ukraine also subtracted.

[30] ENTSOG (2023). *Transparency Platform*. https://transparency.entsog.eu/#/map

[31] Eurostat (2023). *Supply, transformation, and consumption of gas - monthly data.* https://ec.europa.eu/eurostat/databrowser/view/nrg_cb_gasm/default/table?lang=en

[32] Kpler, 2023. *LNG Platform*. https://lng.kpler.com/ [subscription required]

[33] GIE, 2023. *Aggregated Gas Storage Inventory*. https://agsi.gie.eu/data-overview/eu

Conclusions

The global gas market in H1 2023 saw falling prices across the benchmarks noted at the beginning of the Quarterly Review, with TTF front-month, JKM front-month, and the landed price of LNG in North-West Europe all falling substantially in this period. This was largely underpinned by lower year-on-year demand in major importing markets (Europe, China, India, and Japan). However, Q2 also saw notable curtailments of Norwegian pipeline supply to Europe and a return to growth in Chinese LNG imports. Taking H1 as a whole, European demand remained lower year-on-year, and while Chinese LNG imports in H1 2023 (44.9 Bcm) were higher than in the same period in 2022 (41.9 Bcm), they were still not yet back at the 2021 level (53.1 Bcm).

Moving into Q3, the European market saw pipeline imports from Azerbaijan continue at full capacity, while pipeline imports from Russia and North Africa edged higher as pipeline supplies from Norway fell sharply, particularly in September. Sendout from LNG regasification terminals had peaked in April (at a record 468 MMcm/d) before declining month-on-month in every month from May to September, when they reached a low of 297 MMcm/d. With LNG as the marginal source of European supply, this reflects a combination of demand that remained lower year-on-year throughout the summer and storage stocks gradually getting closer to full capacity. At a global level, LNG supply remained 2-4 per cent higher year-on-year in every month from May to September, except July (-1 per cent), while the year-on-year growth in Asian LNG imports accelerated from June onwards.

While prices fell during summer 2023, there remained a definite ‘floor’ under those prices. JKM bottomed out around 9.20-9.40 USD/MMBtu between late May and early June, while TTF front-month bottomed out at 8.25-8.90 USD/MMBtu in mid-July, and both stepped up in September. As noted in our previous Quarterly Review, the continuation of daily price volatility (in Europe in particular) demonstrates that during summer 2023 the European market remained finely balanced. Prices have been just high enough to attract sufficient supply and curb demand, but the perceived lack of flexibility (that is, spare supply capacity) either to cope with a surge in demand or to compensate for a curtailment of one of Europe’s sources of supply meant that the market reacted strongly to any news that could have implications for supply. Examples of this were seen in the market reaction to news of Norwegian maintenance, planned industrial action at Australian LNG export terminals, suspension of production at the Tamar field in Israel at the beginning of October, and even forecasts of colder weather in Europe following a mild end to Q3 in September that lasted into early October.

In the previous Quarterly Review, we wrote that the latter part of Q3 could be characterised by oversupply and downward pressure on prices in Europe as storage facilities are filled, if the weather continues to be mild. In the event, the curtailment of Norwegian pipeline supply and slowdown in LNG sendout meant that storage did not surpass 95 per cent of capacity until 25 September and only surpassed 96 per cent of capacity on 1 October. The ‘short term oversupply’ – and related downward pressure on prompt prices – that was anticipated for late September into October did not materialise.

Looking ahead to Q4, much will depend on when ‘winter proper’ begins in both Europe and North-East Asia, and the point at which Europe begins to draw down its storage stocks. A mild start to the winter in Asia will allow LNG supply to Europe to remain robust without a price rally that becomes dramatic, while a parallel mild start to winter in Europe could allow a delayed start to substantial storage stock withdrawal. Conversely, given the finely-balanced nature of the gas markets at both regional European and global levels, a surge in demand amid supply that has only limited growth potential could cause prices to rise rapidly. It is with this in mind that we offer our winter outlook in the following sections, and the possible implications for summer 2024.

Dr Jack Sharples, Senior Research Fellow, and Mr Mike Fulwood, Senior Research Fellow, OIES

2. European Winter Outlook

Europe Supply-Demand Balance

Looking ahead to winter 2023/24, there appears to be a reasonable degree of visibility regarding several aspects of European gas supply, barring any unforeseen dramatic events.

In the twelve months from October 2022 to September 2023, production within the UK and EU-27 averaged 18 per cent of gross (non-storage) supply[34] within a range of 16-20 per cent. Production in the Netherlands at Groningen averaged 13.4 MMcm/d in the period November 2022 to March 2023, and that supply has now halted. Production from the small fields in the Netherlands averaged 29.6 MMcm/d in the same period. Between July 2022 and June 2023 (latest data), Dutch production from the small fields declined by an average 17 per cent year-on-year. Therefore, our baseline assumption for Dutch production in winter 2023/24 is zero production from Groningen and a 17 per cent year-on-year decline in the Dutch production from small fields. Production in the rest of the EU is assumed to continue its modest decline of -3 per cent year-on-year while UK production continues its own modest decline of -2 per cent year-on-year. The overall supply from EU+UK production in the winter months from October 2023 to March 2024 is assumed to be 91 MMcm/d from the UK, 25 MMcm/d from the Netherlands, and 70 MMcm/d from the rest of the EU, giving a total of 186 MMcm/d (5.6-5.8 Bcm per month).

Pipeline imports from Azerbaijan are likely to continue at the full capacity of the Trans-Adriatic Pipeline (TAP) on the Turkey-Greece border (32 MMcm/d, or 0.96-0.99 Bcm per month), while pipeline imports from North Africa are assumed to continue at 92 MMcm/d (2.75-2.85 Bcm per month). This estimate for pipeline supply from North Africa is the average for 1-20 October and very similar to the averages for the period October 2022 to March 2023 (90 MMcm/d) and the twelve months from October 2022 to September 2023 (93 MMcm/d).

Pipeline imports from Russia are assumed at 75 MMcm/d (2.25-2.33 Bcm per month), with an approximate 50-50 split between volumes delivered via Ukraine (to Slovakia, Austria, and Hungary) and volumes delivered via Turkish Stream (to Greece, North Macedonia, Serbia, Bosnia-Herzegovina, Croatia, and Hungary). This figure of 75 MMcm/d is about 12 per cent higher than the average for the past 12 months (67 MMcm/d) and higher than the average for winter 2022/23 (64 MMcm/d), but slightly lower than the average for the period 1 July to 20 October 2023 (77 MMcm/d), and particularly for the period 10-20 October, when flows averaged 84 MMcm/d amid colder weather and rising prices.

While rising prices in the first half of winter may make offtake under long-term contracts (with prices based on the front-month index) commercially more attractive than day-ahead spot purchases, the reverse may be true if prices begin to decline in late winter. With this in mind, Russian pipeline supply could remain at the current level of 75-85 MMcm/d into the first half of winter and then fall back to 65-75 MMcm/d in late winter, thus giving a whole winter average closer to 75 MMcm/d.

Pipeline imports from Norway are assumed to be 335 MMcm/d, which is similar to winter 2022/23 (334 MMcm/d, higher than winter 2020/21 (315 MMcm/d) and below winter 2021/22 (345 MMcm/d). This reflects that while the maintenance conducted over summer 2023 will hopefully have left Norwegian infrastructure in good shape, the exceptionally high Norwegian supply over winter 2021/22 was also driven by additional production due to the priority given to gas exports over gas reinjection at oil fields for enhanced oil recovery. The lower prices expected in winter 2023/24 may mean an absence of such additional export of gas that would normally be reinjected during oil production. In total, a Norwegian supply of 335 MMcm/d equates to 10.2 Bcm per month.

[34] That is, combined supply from production, pipeline imports, and sendout from LNG regasification terminals

As discussed below, the outlook for global LNG supply and LNG demand outside Europe suggests that the volume available for import into Europe in winter 2023/24 could be relatively unchanged year-on-year. If sendout from European regasification terminals is also similar to winter 2022/23, this would suggest an average sendout of 424 MMcm/d. Specifically, last winter, Europe saw sendout rise from 367 MMcm/d in October 2023 to sustained highs of 443-456 MMcm/d in November, December, and February. A dip to 423 MMcm/d in January was later followed by an end-of-winter figure of 413 MMcm/d in March. Therefore, while a single figure for LNG sendout is provided below for the purpose of an overall view, it is worth noting that LNG sendout varies far more greatly on a daily and monthly basis than EU+UK production and pipeline imports from Norway, Russia, North Africa, and Azerbaijan.

Taken together, production of 5.67 Bcm per month, pipeline imports of 1 Bcm per month (Azerbaijan), 2.8 Bcm per month (North Africa), 2.3 Bcm per month (Russia), and 10.2 Bcm per month (Norway), combined with LNG supply of 12.9 Bcm per month, provides total gross (non-storage) supply of 33.87 Bcm per month.

The winter of 2022/23 saw mild temperatures and price-driven conservative consumer behaviour reduce gas demand for space heating in the residential sector year-on-year, although European power generation was substantially affected by a number of French nuclear reactors being offline in that period. Looking ahead to winter 2023/24, we start from a baseline assumption of gas demand being the same as in winter 2022/23.

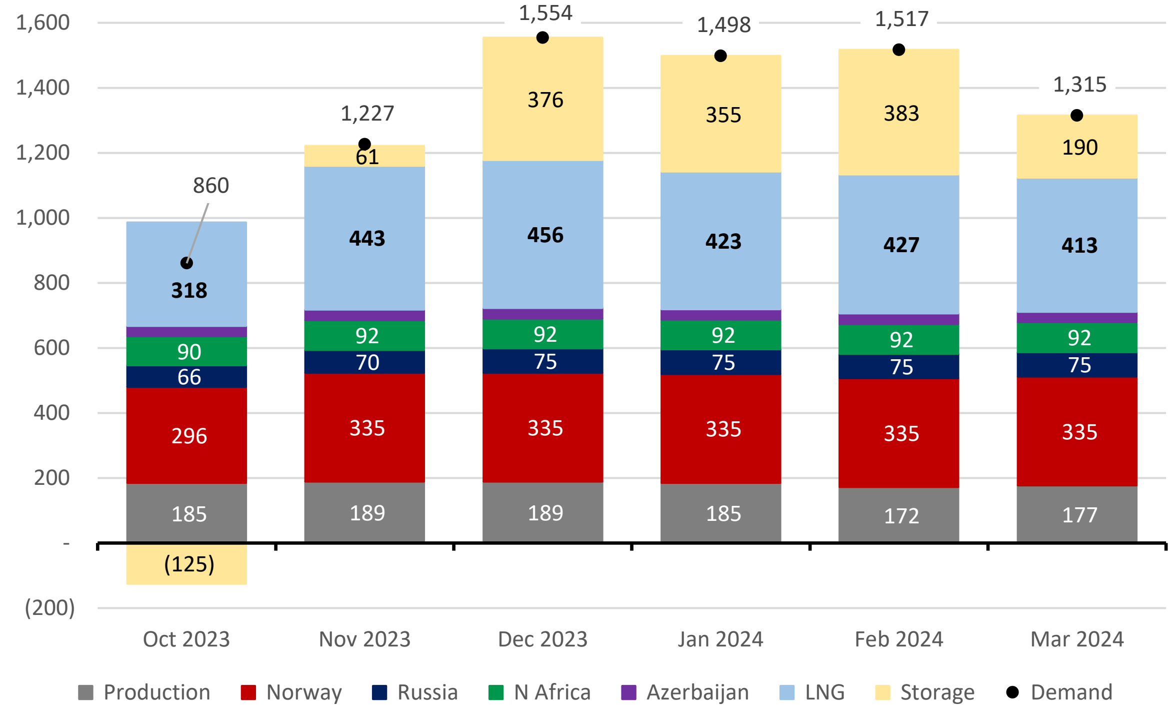
Two factors support this assumption. Firstly, temperatures are unlikely to be milder year-on-year, which means that temperature-driven residential gas demand for space heating is also unlikely to be lower year-on-year. Secondly, wholesale prices are likely to be lower year-on-year, which means that residential, commercial, and industrial demand profiles are going to face less pressure from high prices. Taken together, these two factors mean that winter 2023/24 is likely to see a set of temperature and price conditions that place less downward pressure on commercial, residential, and industrial gas demand than they did in winter 2022/23.

Conversely, with French nuclear power generation likely to be higher year-on-year, along with the continued buildout of renewable sources of power generation across Europe, gas demand for power generation is likely to be lower year-on-year. So, it may be reasonable to start from a baseline scenario in which these upside and downside factors balance each other out, and result in gas demand that is similar year-on-year.

In this baseline scenario, storage withdrawals are the balancing item. Given the assumptions above, including the seasonal shape of demand and the flexibility of LNG sendout relative to other forms of supply, storage stocks could peak at absolutely full capacity (1,138 TWh or 106.5 Bcm) in late October, and limited withdrawals in November could leave stocks still above 100 Bcm by 1 December. In the period 1 November to 31 March, total withdrawals of 41.5 Bcm could leave stocks at the end of winter as high as 65 Bcm. Such a limited withdrawal from storage would significantly reduce the volume that would need to be reinjected into storage in summer 2024, in order to begin winter 2024/25 with stocks once again at full capacity.

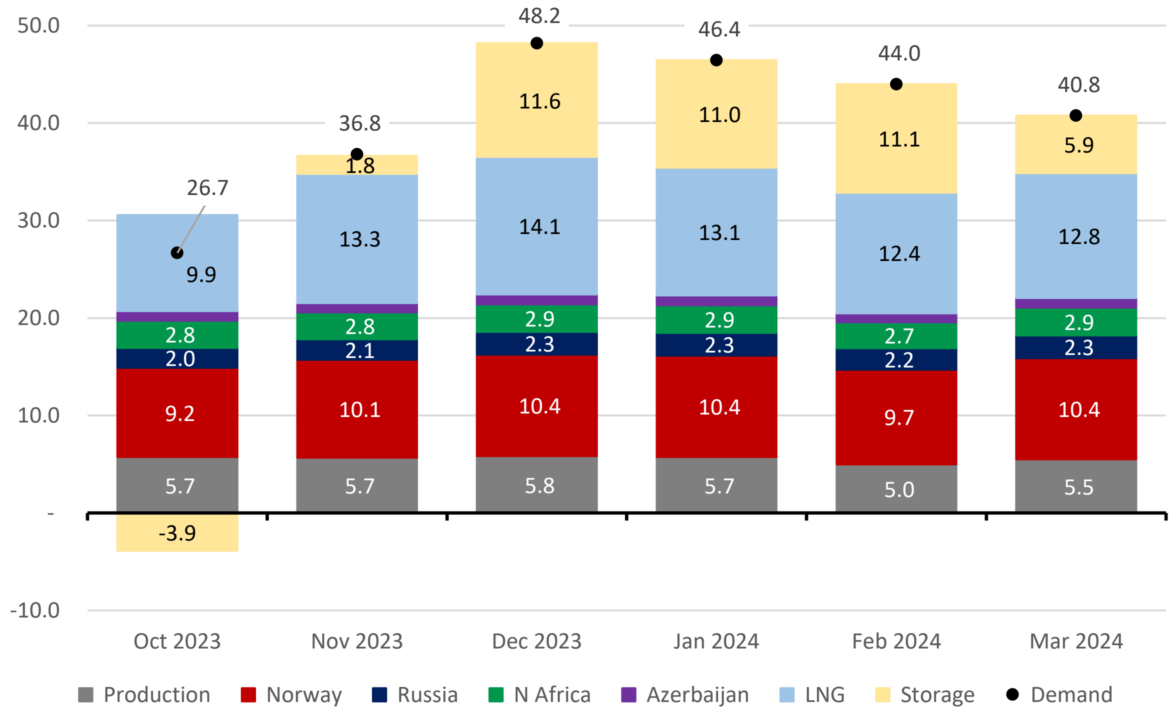
Finally, it should be noted that the graphs below are based on daily actual data for the period 1-20 October, while the period 21 October to 31 March is based on estimates derived from the assumptions outlined above.

Figure 2.1: Europe Gas Balance in Winter 2023/24 (MMcm/d)



Source: National Gas (UK), ENTSOG, GIE AGSI+, GIE ALSI+, Kpler, OIES estimates

Figure 2.2: Europe Gas Balance in Winter 2023/24 (Bcm per month)



Source: National Gas (UK), ENTSOG, GIE AGSI+, GIE ALSI+, Kpler, OIES estimates

Global LNG Market

The balancing of the European gas market in recent years, especially during the energy crisis following the Russian invasion of Ukraine, has led to heavy reliance on supply from the global LNG market. Europe was traditionally seen as the balancing market for LNG. The surge in LNG supply in 2019 largely ended up in European storage, as demand for LNG outside Europe (most notably in Asia), failed to keep pace with the rising supply. The post-Covid recovery and cold northern hemisphere winter in 2021 saw LNG rush to satisfy Asian demand, with Europe drawing down gas in storage (in effect the LNG built up in 2019) to meet its higher cold-weather demand.

That situation changed dramatically in 2022, with Europe becoming more a baseload than balancing market, as it sought to replace the lost Russian pipeline imports. The LNG market is now effectively operating at full capacity, with utilisation of 'real world' (as opposed to nameplate) LNG liquefaction capacity running at over 98 percent.[35] In effect, there is no spare LNG available to offer to markets which are short. How the European market balances this winter, therefore, will depend crucially on the global supply of LNG and the demand for LNG in the rest of the world, especially in Asia. Part 1 of this Quarterly Review discussed the LNG supply and demand balance so far this year. Global LNG supply is up by some 10.8 Bcm in the first nine months of the year – measured on a delivered to importing countries basis[36] – and Asian LNG demand is up on 2022 by some 4.2 Bcm (largely driven by China) leaving additional supply for other markets.

In terms of the **global LNG supply**, looking at the October to March winter period, LNG export capacity is projected to be 15.5 Bcm higher in 23/24 than in 22/23. Over 11 Bcm of this increase is from the return of Freeport in the US. There was no supply last winter from Freeport and the plant is now approaching full capacity again. There are also smaller increases from Algeria (more feedgas), Mozambique (ramping up of Coral FLNG), and Trinidad (more feedgas). Additionally, on 19 October, BP announced that Tangguh Train 3 in Indonesia shipped its first cargo, while start-ups are expected for the Altamira FLNG in Mexico (November), Arctic LNG 2 Train 1 in Russia (mid-January), and possibly the Greater Tortue plant in Senegal/Mauritania (first gas in Q1 2024 and first commercial LNG exports three months after that). These increases are partly offset by the expected temporary closure of the Darwin plant in Australia until new feedgas is available. Allowing for some uncertainty it could be assumed that 90 percent of this 15 Bcm increase will be realisable – 13.9 Bcm. The suspension of production at the Tamar field in Israel could cause Egyptian LNG exports to halt entirely. However, Egyptian LNG exports had already fallen from 0.35 mt in May 2023 to a total of 0.18 mt (three small cargoes) for the period from 1 June to 20 October, so the impact on LNG markets could be limited, unless the curtailment of Israeli supply to Egypt means that Egypt will once again become a net importer of LNG, as it was between April 2015 and September 2018.

On the demand side, Asia will be a key factor in soaking up the increase in supply. Within Asia, **China** is where the largest increase in demand will be between winter 22/23 and winter 23/24. Gas demand in China went down slightly in 2022 as a result of the impact of the Covid lockdowns and with production and pipeline imports continuing to rise, LNG imports fell sharply by some 22 Bcm. The year-on-year decline in China LNG imports was not reversed until March of this year, but since then growth has returned, with the average year-on-year increase in Chinese LNG imports since March being just under 1.4 Bcm/month. Gas demand is now rising in China, and is up some 7 per cent year-on-year. Domestic production continues to rise as do pipe imports from Russia, although pipe imports from Central Asia are not rising. As a consequence, LNG imports have risen. Looking ahead to this winter, continued growth in LNG imports might be expected as last winter (apart from December) LNG imports were weak. If LNG imports were to continue to be higher at 1.4 Bcm/month (excluding December), then over the winter period total China LNG imports would be 7 Bcm higher year-on-year.

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[35] Based on OIES calculation using the NexantECA World Gas Model.

[36] Measured on the basis of exports leaving plants the growth is some 13 Bcm year on year suggesting the measured imports will continue to rise.

Japan, South Korea, and Taiwan (JKT) is the largest group of Asian LNG importers. While Taiwan has been flat this year, South Korean volumes so far are down some 1.5 Bcm and Japan a huge 8.5 Bcm. In Japan's case, the economy has been weak and nuclear plants have increased output, thus reducing gas consumption. As the winter season begins, however, demand for LNG could return to levels similar to those seen last winter. Japan's LNG stocks are now relatively low, although South Korea's are at higher levels. Taiwan's LNG imports are not particularly variable month-to-month and a small increase might be expected over the winter. Overall, a baseline assumption for the winter for JKT is to be flat year-on-year.

ASEAN has been the strongest growing area within Asia and has been consistently growing month-by-month since early 2021. The core importers - Thailand, Singapore, Indonesia and Malaysia - have now been joined by the Philippines and Vietnam. Since the last quarter of 2021, the year-on-year growth each month has been just under 0.5 Bcm. There seems little reason to think that this trend will not continue this winter, which would give growth of some 3 Bcm compared to last winter.

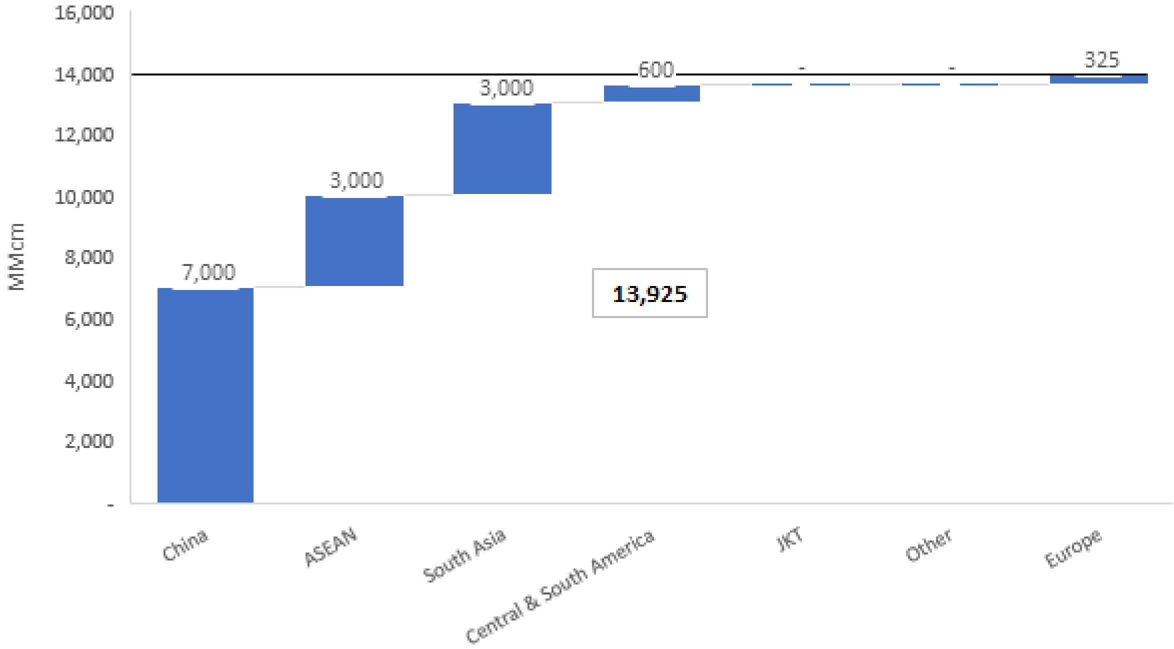
South Asia (India, Pakistan, and Bangladesh) saw a sharp fall in LNG imports in 2022 of some 8 Bcm in aggregate or some 17 percent. This was as a result of the very high spot prices and the non-delivery of contracted volumes to Pakistan. This weakness continued in the first half of 2023, with volumes being below the already weak 2022 level. However, LNG imports have risen sharply since July, with spot prices much lower. Monthly imports 0.5 Bcm higher year-on-year – 3 Bcm in total over the six months of winter 2023/24 – would take LNG imports back to just above the level of winter 2021/22, but still well below the previous two winters including the Covid-hit period.

Central and South America (C&SA) LNG imports have been very volatile over the last few years. 2021 saw a 75 percent increase in LNG imports as the drought saw large falls in hydro output in Brazil and Chile combined with lower Argentina domestic production. This was completely reversed in 2022, and LNG imports fell back to 2020 levels with plentiful hydro power reducing the need for LNG imports. There has been a small recovery in 2023, but much of this has been in the Caribbean, with El Salvador being a relatively significant importer, plus increased LNG demand in Colombia. Brazil's LNG imports remain weak, having imported very few cargoes last winter between October 2022 and March 2023. With the Caribbean and Colombia growing and some likely pick up in Brazil, average year-on-year growth of 0.1 Bcm/month looks possible. This would equate to 0.6 Bcm more LNG demand in the region over the course of winter 2023/24.

The other LNG importers include **North America, North Africa, and the Middle East**. LNG imports into North Africa have been few and far between for the last five years since Egypt stopped importing. North American imports are also at very low levels into both Boston harbour and Mexico. Middle East import volumes have, until recently, been largely into Kuwait, with Dubai importing some this summer. Winter volumes typically drop off after the summer cooling season (with air conditioning driving gas demand in power generation). Overall, for these other LNG importers, a baseline assumption would be for no overall growth year-on-year.

The waterfall chart below summarises our assumptions on LNG imports into the main regions.

Figure 2.3: Change in LNG Imports – Winter 2023/24 vs Winter 2022/23



Source: Kpler, OIES estimates

Given the expected growth in LNG supply and the assumed LNG import growth outside Europe, the residual amount available for Europe is a small rise of 0.3 Bcm for winter 2023/24 against winter 2022/23, pretty close to an unchanged level.

Key Uncertainties

The scenario illustrated in Figure 2.1 and 2.2 is subject to a number of uncertainties. A major factor in the balance – and the volume withdrawn from storage – is demand. The use of gas for space heating across Europe means that the seasonal variation (and in particular, the size of the winter peak) in European gas demand is weather-related. Logic would suggest that the milder the previous winter, the lower the likelihood that the coming winter is milder still, and that would appear to be the case at present.

While pipeline imports from Norway, Russia, North Africa, and Azerbaijan are relatively stable, the experience of Norwegian (planned and unplanned) maintenance over summer 2023 illustrated the impact that such maintenance can have. Furthermore, while Russian gas has continued to flow via Ukraine despite the war, a disruption in flows on this route cannot be ruled out.

A final uncertainty for Europe concerns LNG imports. Europe's LNG regasification capacity now far exceeds its actual imports on an annual basis, with more regasification capacity due online in Germany and Greece during winter 2023/24. However, regasification capacity is one thing, and access to LNG cargoes is quite another. The current balance of the global LNG market suggests that there is unlikely to be a substantial physical shortage of supply, but any tightening of the global LNG market (through either curtailment of supply or surge in demand) will almost certainly raise the price that European buyers will need to pay to purchase spot cargoes (for example, from portfolio players) during the coming winter. With LNG (along with storage withdrawals) the marginal supply to Europe in the winter, the finely-balanced nature of the market means that uncertainty in the outlook for prices reflects the difficulty in accommodating a shift in fundamentals at short notice.

The central case outcome for winter 2023/24 for the LNG market and the implications for Europe look reasonably comfortable with Europe able to import as much LNG in winter 2023/24 as in winter 2022/23. The expected rise in global LNG supply allows rising LNG demand, especially in China, to be accommodated. Barring unexpected technical and feedgas issues, the rise in LNG supply is largely locked in, with much of the growth coming from the return of Freeport. The potential of strikes by workers at Gorgon and Wheatstone in Australia, however, remain a risk. Exports from these two plants in aggregate are around 3 Bcm, much of it destined for Japan, plus smaller volumes to China, South Korea, and Taiwan. While it seems unlikely that both plants would be shut for the whole of the northern hemisphere winter, arithmetically the loss of these volumes would wipe out all the projected rise in global LNG supply.

On the LNG demand side, the assumption is of Asian LNG demand growth, year-on-year, of some 13 Bcm, driven mostly by China. JKT are, in aggregate assumed to be flat, year-on-year, which is somewhat more optimistic than the substantial year-on-year decline in import volumes seen in 2023 to date. Lower than expected JKT demand is, therefore, a distinct possibility with more coal and nuclear in the mix in Japan and more coal in South Korea. The anticipated growth in Asian LNG demand is not predicated on a cold winter, but the risk of that remains. In the cold northern hemisphere winter of 2020/21, Asian LNG demand was some 15 Bcm higher than in the 22/23 winter, although that was with higher underlying China demand, and also 15 Bcm higher than in the prior 2019/20 winter. Another cold northern hemisphere winter, therefore, could easily add some 10 to 15 Bcm to Asian LNG demand, with LNG being the marginal molecule.

Higher LNG demand, and possibly a supply disruption due to factors like the Gorgon/Wheatstone strikes (although these now appear to have been called off), would pull LNG away from Europe. In such circumstances, this winter could be a repeat of the 2020/21 winter, when LNG cargoes (especially from the United States) flowed to Asia rather than Europe. Europe responded by drawing down its ample stocks of gas in storage, with little impact on the TTF price. The TTF price did not start responding until the summer of 2021 as the need to refill storage came up against the post-Covid economic recovery and then the beginnings of the reductions in Russian pipeline exports to Europe. A cold northern hemisphere winter in 2023/24, with any supply disruption as well, could see a repeat of winter 2020/21, when European storage stocks were drawn down substantially to offset the diversion of LNG cargoes to Asia, with the knock-on effect of increasing the volumes needed for the replenishment of European storage in summer 2024.

Summer 2024

Looking ahead to summer 2024, the key issue for Europe will be the volume of injection necessary to restore storage stocks to full capacity by the beginning of winter. The seasonal price spreads between summer 2024 and Q1 2025 are likely to be wide enough to drive injections, as the market prices in uncertainty over the Russia-Ukraine gas transit contract, which expires on 31 December 2024.

If Russian gas transit via Ukraine does halt at the end of 2024, the impact will be felt mainly in Slovakia and Austria, where SPP and OMV (respectively) have long-term contracts for supply from Gazprom, delivered via Ukraine. In addition, of the 4.5 Bcma that MVM currently purchases from Gazprom for supply to Hungary, around 1 Bcma is delivered via Ukraine (Slovakia, and Austria) and around 3.5 Bcma is delivered via Turkish Stream (Bulgaria, and Serbia). SPP and OMV would need to find alternative sources, most likely via a combination of increased LNG supply into northern Germany being delivered to Central Europe via the Czech Republic to Slovakia and across the German-Austrian border, and increased LNG imports into northern Italy underpinning a ramp-up of physical supply from Italy to Austria at Tarvisio (Arnoldstein). This will have the effect of pushing up midwinter prices in both Italy and Germany, with the impact also likely being felt at TTF.

With very limited upside potential for supply from European production and pipeline imports in summer 2024, compared to the levels of summer 2023 (except for a rebound in Norwegian summer pipeline supply), a European summer market balance that was sufficiently loose to put downside pressure on prices would require a third consecutive summer of lower year-on-year demand. Alternatively, a looser global LNG market could bring down the price of LNG as the marginal source of supply, even if the volume of European LNG imports did not rise substantially year-on-year in summer 2024, on the back of that looser global market.

With that in mind, summer 2024 is likely to see a number of new LNG export projects coming on and others ramping up, meaning that global LNG export capacity is expected to rise significantly. Supply will be ramping up from Tangguh Train 3 in Indonesia, the Altamira FLNG in Mexico, Arctic 2 Train 1 in Russia, and the Greater Tortue plant in Senegal/Mauritania, more feedgas is expected in Trinidad and a recovery in Nigeria, plus maintenance turnarounds in Sakhalin in Russia and Malaysia. In the second half of the year, Golden Pass in the US is slated to startup. For 2024 as a whole, LNG export capacity is projected to grow by some 29 Bcm, with summer 2024 capacity being almost 14 Bcm higher than in summer 2023.

On the LNG demand side, growth in China may slow somewhat. Even with gas demand in China growing strongly, the rise in domestic production and the final ramp up in Russian flows on Power of Siberia 1, together with some recovery in flows from Central Asia, may limit the growth in LNG imports. Elsewhere in Asia, JKT volumes were low this summer and some recovery is possible, with ASEAN and South Asia also continuing to grow. Overall, Asian LNG imports could grow by 10 Bcm between summer 2024 and summer 2023.

The remaining increase in the LNG supply could be taken by Central and South America. Demand in the Caribbean and Colombia are rising and the current El Niño in the Pacific raises the prospect of lower rainfall in Brazil, especially, hitting the output of hydro plants, leading to higher LNG imports. In April to September 2023, Brazil imported 0.6 Bcm of LNG, compared to 1.2 Bcm in summer 2022 and 5.1 Bcm in summer 2021, when the low rainfall impacted hydro output.

Higher LNG imports into Central and South America, plus the projected 10 Bcm rise in Asian LNG imports, could take up largely all the rising supply. This would leave Europe being able to import a similar amount of LNG in summer 2024 as in summer 2023. In the event that Europe has ample gas in storage at the start of the summer injection period, a similar level of LNG imports as in 2023 would be likely to enable storage to fill again comfortably. However, to the extent that Europe has to deplete its storage more rapidly this winter, either due to cold weather and/or possible supply disruptions, then the summer 2024 LNG market could become very tight as Europe competes strongly with Asian and other markets for LNG.

Conclusions

To conclude, the stocks held in European storage, their depletion over the course of the coming winter, and their replenishment next summer, are likely to be a key metrics for the state of the European gas market, and a key factor in front-month and forward prices.

A benign scenario of Europe ending winter 2023/24 with stocks in excess of 60 Bcm on 31 March, and the prospect of repeating net storage injections of around 43 Bcm in summer 2024 (the same as summer 2023), appears comfortable. An added bonus this time would be Norwegian pipeline supply back at normal levels to more than offset another year of European production decline, together with LNG imports and other pipeline imports once again at summer 2023 levels. This represents a relatively comfortable scenario, especially if European gas demand does not rebound year-on-year.

Conversely, a cold winter across the northern hemisphere, with LNG pulled away to Asia at a time of surging European demand, resulting in a substantial drawdown of European storage stocks, could leave summer 2024 looking very much like an uphill tight-market struggle, with prices accordingly higher.

Taking a geographically broader, slightly longer-term view, Europe currently finds itself in a market situation that may persist for at least the next 2 years. With every winter outlook, it is hoped that supply remains robust, demand remains stable (as opposed to substantially higher year-on-year), and that Europe ends the winter with a limited storage drawdown requiring a limited storage replenishment. This constrained market situation, in which supply and demand are finely balanced and lacking flexibility to react to a sharp shift in fundamentals, is likely to persist until the next substantial wave of LNG supply hits the global market, most notably from Qatar and the United States, in the period 2025-2027. Therefore, it is quite possible, even likely, that twelve months from now, our winter outlook for 2024/25 will not see much in the way of additional supply available for Europe, with the addition of greater concern over the future of Russian pipeline supply, storage stocks as a seasonal buffer, and LNG as a marginal source of supply whose importance to Europe continues to grow. In short, Europe is more exposed to the dynamics of the global LNG market than ever before, and that situation will persist through winter 2023/24 into summer 2024, and beyond.

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